AD-A081 383 ACRUEX CORP MOUNTAIN VIEW CA ENERGY AND ENVIRONMENTAL DIV F/G 10/3
APPLICATION POTENTIAL OF ENERGY SYSTEMS AT NAVY SITES. VOLUME I--ETC(U)
JAN 80 S J ANDERSON, M D JACKSON, S J CHAMP N68305-78-C-0009

UNCLASSIFIED CEL-CR-80.006-VOL-1 NL

1 OF 3

AD
A081383

LEVEL II

A081384

12

CEL

CR80.006-VOL-1

CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, CA 93043

Sponsored by

Naval Material Command

Final rept. Mar 78-Oct 79,

APPLICATION POTENTIAL OF ENERGY SYSTEMS AT NAVY SITES, VOLUME I: METHODOLOGY AND RESULTS.

Jan[redacted]80

273

An Investigation Conducted by

LACRUEX CORPORATION New
Energy & Environmental Division
Mountain View, CA 94042

S. J. Anderson
A. D. Jackson
S. J. Champ.

N68305-78-C-0009

Approved for public release; distribution unlimited.

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE

READ INSTRUCTIONS BEFORE COMPLETING FORM

1. REPORT NUMBER: CR 80.006
2. GOVT ACCESSION NO.
3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle): Application Potential of Energy Systems at Navy Sites, Vol. I: Methodology and Results, Vol. II: Navy Energy Siting (NES) Computer Program User's Manual
5. TYPE OF REPORT & PERIOD COVERED: Final Mar 78 - Oct 79
6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s): S. J. Anderson, M. D. Jackson, S. J. Chaump
8. CONTRACT OR GRANT NUMBER(s): N68305-78-C-0009
9. PERFORMING ORGANIZATION NAME AND ADDRESS: Acurex Corporation, 485 Clyde Avenue, Mountain View, CA 94042
10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS: A0371-01-010
11. CONTROLLING OFFICE NAME AND ADDRESS: Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA 93043
12. REPORT DATE: Oct 1979
13. NUMBER OF PAGES: Vol I - 278, Vol II - 90
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office): N/A
15. SECURITY CLASS. (of this report): U

15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)
18. SUPPLEMENTARY NOTES
19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Alternative energy; Cost effectiveness; Economics; Forecasting; Fuel oil; Linear programming; Naval industrial facilities; Nonlinear programming; Optimization; Systems engineering

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

Application of renewable and nonrenewable energy conversion technologies are forecast for the Navy's ten largest industrial locations and four smaller locations. Data are obtained from an optimization model that determines the least, life-cycle cost energy supply system for an industrial location. Optimal solutions were composed of integrated combinations of energy

DD FORM 1473, 1 JAN 73 — EDITION OF 1 NOV 65 IS OBSOLETE

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

Cont. conversion technologies. Besides being more cost-effective than status quo systems fired exclusively on fuel oil, the optimal integrated systems displace a significant percentage of fuel oil.

Energy conversion technologies that participate in the optimal supply systems for large Naval industrial locations include fluidized-bed coal combustion, cogeneration, oil-fired systems, with smaller contributions from refuse derived fuel systems. Oil-fired systems participate only in a peaking capacity wherever coal cumbustion is permitted. Otherwise, the status quo systems are forecasted to prevail.

Renewable energy conversion systems were not competitive in plant-size configurations at nine of the ten large Naval industrial locations studied, Pearl Harbor being the exception.

FOREWORD

This report documents the work performed by Acurex Corporation, Energy and Environmental Division, Mountain View, California for the Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California. This work was performed on Contract N68305-78-C-0009.

The report is presented in two volumes: Volume I, Methodology and Results, and Volume II, Navy Energy Siting (NES) Computer Program User's Manual. Volume I includes two appendices: Appendix A, Energy Systems Characterization, and Appendix B, Results for the Top Ten Consumers and Sample Survey Bases.

Dr. T. A. Shugar was the technical monitor for the Civil Engineering Laboratory. Mr. R. H. Thomas was the Energy and Environmental Division's Project Manager and Mr. M. D. Jackson was the Project Engineer. Mr. S. J. Anderson and Mr. S. J. Chaump provided valuable capabilities throughout the project. The authors also acknowledge the contributions of Dr. M. J. Hemsch during the initial formulation of the methodology.

The support and suggestions provided by the Civil Engineering Laboratory throughout this project were greatly appreciated.

SUMMARY

With dwindling supplies of natural resources and the Nation's reliance on oil imports, the Navy has initiated several programs aimed at reducing the dependency of shore-based activities on petroleum products. The goals of these programs are to reduce overall consumption through conservation and to displace petroleum usage with alternate energy sources. Alternate systems are currently being evaluated in the Energy Exploratory Development Program at the Civil Engineering Laboratory. Determining the potential value of these systems throughout the Naval Shore establishment was the objective of this study.

The study was divided into two phases: (1) Developing a long term, uniform method for evaluating the present worth of alternate systems; and (2) Performing a complete survey of energy systems, leading to energy self sufficiency at Navy bases. Constructing the methodology consisted of collecting and modeling data on system performance and cost, energy consumption and site factors. Emphasis was placed on matching critical operational and economic characteristics of alternate systems with base-specific siting and energy demand requirements.

The methodology was then used to perform a Navy-wide survey. This survey concentrated on analyzing the Navy's top ten energy consumers. A select sample of smaller bases was also analyzed. These results were

combined, yielding an optimum mix of alternative and conventional energy sources throughout the shore establishment.

This section summarizes both the methodology and survey results.

Methodology

The survey methodology was developed to determine the optimum mix of alternative and conventional energy sources throughout the shore establishment. We sought an optimization technique that minimized energy costs, yet matched energy and other base-specific requirements. A nonlinear programming approach was selected.

The optimization procedure was incorporated into a computer code along with 19 different energy models and data manipulation routines. Site data affecting technology performance and costs were preprocessed to form an energy demand and cost data file. The systems modeled are summarized in Table S-1. As shown, alternate systems -- ranging from renewable energy sources to conventional sources -- competed against commercial electricity purchases and replacement costs for oil-fired boilers. The end-use sectors were defined based upon the accuracy and availability of existing Navy data.

The entire procedure was constructed to optimize the energy supply for an individual base instead of the entire shore establishment. The technology impact for the shore establishment was accomplished by summing and extrapolating individual results. Furthermore, the energy demand was restricted to facilities -- transportation and operational requirements were excluded. Conservation was also not modeled. Instead, we assumed future conservation efforts would cancel any growth in energy requirements.

TABLE S-1. LIST OF ENERGY SYSTEMS MODELED

Energy Sector	Alternate Systems	Conventional Systems
HEATING	Solar Thermal Refuse Derived Fuel (RDF) Coal-fired Fluidized Bed Combustion (FBC) Conventional Coal Combustion	Oil-fired boilers (replacement)
STEAM	Refuse Derived Fuel (RDF) Coal-fired Fluidized Bed Combustion (FBC) Geothermal Conventional Coal Combustion Coal-fired Steam Topping Cycle (Cogeneration)	Oil-fired boilers (replacement)
ELECTRICITY	Refuse Derived Fuel (RDF) Coal-fired Fluidized Bed Combustion (FBC) Coal-fired Steam Topping Cycle (Cogeneration) Conventional Coal Combustion Geothermal 5 kW Wind Generator 200 kW Wind Generator 1500 kW Wind Generator Photovoltaic	Commercial Purchases

Navy-Wide Survey Results

To estimate the present value of emerging technologies, we performed an analysis of the top ten energy consumers and a select sample of smaller installations. The results were combined to give an overall estimate for the shore establishment. The economic parameters for each analysis were unchanged. Each system modeled was assumed to have a 25-year economic life. We used 1977 as our base year and all systems were assumed to be implemented in 1985. A 10 percent discount rate and differential inflation rates on fuel prices were used based on current Navy recommendations.

The combined results for the top ten consumers are illustrated in Table S-2. For each energy sector, we summed the mix of alternate and conventional sources yielding the lowest cost at each Navy base. Cost savings were established by comparing the optimum mix in each sector to energy-weighted costs of either replacing oil-fired boilers or purchasing commercial electricity. Savings in oil consumption were merely summed.

As indicated, coal and RDF systems were found to be most cost effective in all three energy sectors. This is not too surprising since these systems cost considerably less than other alternatives, especially for bases that are the size of the top ten energy consumers. The annualized costs of coal and RDF systems were very close and the mix depended on available refuse, local coal prices, and the size of the demand. In general, coal systems were most cost-effective at large demands.

Coal systems were excluded at four bases located in regions which currently do not meet proposed federal air quality standards or, in the case of Pearl Harbor, have prohibitive costs. At these bases, RDF

TABLE S-2. SUMMARY OF COMBINED RESULTS FOR NAVY'S TOP TEN ENERGY CONSUMERS

Energy Sector	System	Fraction of Demand Met %	Delivered Energy (10^9 Btu/yr)	Initial Capital Costs (10^6\$)	Total Annual Costs (10^6\$)	Average[a] Energy Costs (\$/10^6 Btu)	Oil[b] Consumed (10^3 (bbls/yr)
HEATING	RDF	1.10	126.6	2.33	0.56	4.08	--
	FBC	43.29	4997.0	51.22	29.56	3.88	--
	Solar Thermal	0.53	61.4	5.25	0.69	10.99	--
	Oil-fired boilers	55.08	6358.0	32.76	58.07	9.13	1419.0
	Oil-fired boilers alone	100.0	11543.0	44.12	101.17	8.76	2577.0
STEAM	RDF	1.07	111.0	2.07	0.50	4.53	--
	FBC	25.14	2604.0	24.15	12.11	3.98	--
	Cogeneration	26.39	2733.0	46.03	19.96	5.40	--
	Oil-fired boilers	47.40	4910.0	21.03	48.08	9.79	1201.4
	Oil-fired boilers alone	100.0	10358.0	33.13	98.49	9.51	2551.0
ELECTRICITY	RDF	2.63	240.9	11.79	2.55	10.60	--
	FBC	42.27	3866.0	81.91	44.42	9.54	--
	Cogeneration	6.11	558.6	--[c]	--[c]	5.40	--
	1500 kW Wind	3.21	293.4	45.00	8.33	27.86	--
	Commercial	45.78	4187.1	--	129.44	30.92	--
	Commercial alone	100.0	9146.0	--	252.15	27.57	--
Total optimum mix		100.0	31047.0	323.5	354.27		2620.4
Total commercial/ oil alone		100.0	31047.0	77.3	451.81		5128.0

SAVINGS = \$97.5 MILLION PER YEAR
OIL SAVED = 2.507 MILLION BARRELS PER YEAR

[a]Life cycle costs, weighted average based on energy delivered
[b]Oil source does not include potential savings by utilities
[c]Cogeneration costs included in steam sector

electric systems were more cost-effective than RDF heating or steam systems. Also at Pearl Harbor, solar and wind systems were cost effective in meeting a portion of the heating and electrical demands, respectively.

The largest cost savings were obtained in the electrical sector. In all cases, it was most cost effective to use alternate systems to generate on-base electricity. The relatively high price of electricity compared to FBC or cogeneration forces the optimization procedures to minimize electricity purchases. Conversely, in the heating and steam sectors, replacing oil-fired units was less cost-effective.

Oil-fired boilers or electricity purchases always supplied some portion of the demand. The actual penetration depended upon demand variations, costs and whether coal was excluded. In all cases these systems were chosen as peaking units reducing the size and costs of competing alternate systems. When coal was excluded, however, most of the requirements were met by oil-fired units in the heating and steam sectors and commercial purchases of electricity in the electrical sector.

The combined mix of energy systems indicate that the Navy can save $97.5 million per year by investing $246 million. This is a 2.5-year return on investment. Further, this investment reduces oil consumption by 2.5 million barrels per year and represents nearly 50 percent self sufficiency. Obviously, these numbers are substantially affected by escalation of conventional fuel prices over the analysis timeframe. In fact, the results illustrate that the Navy would be paying nearly $500 million annually without investing in alternate technologies. This is approximately $100 million more than the Navy currently pays for its entire annual utility bill.

The mix of alternate systems for the smaller installations was similar to the top ten results. Displacing commercial purchases of electricity proved the most cost-effective. The mix included RDF and oil-fired systems in the heating sector; cogeneration, conventional coal combustion and oil-fired systems in the steam sector; and cogeneration, conventional coal combustion and commercial electricity in the electrical sector. In contrast to the top ten results, conventional coal combustion systems were more cost effective than FBC systems for smaller demand sizes.

The combined results for the top ten and the extrapolated results for the small installations yield a potential Navy-wide savings of $340 million per year with an investment of $751 million. This investment reduces oil consumption by 5.6 million barrels per year and, in the aggregate, represents approximately 54 percent self-sufficiency. These numbers are substantially affected by inflated fuel prices.

Overall, the results quantify a minimum cost approach for future energy requirements. Optimum mixes of alternative and conventional energy sources at individual installations are identified. However, actual implementation of these systems requires a far broader scope than can be reasonably modeled. Implementing coal systems, for instance, requires detailed consideration of a number of site factors such as fugitive emissions, flammability, and ash removal. These factors are only modeled generically in terms of system performance and cost data. The methodology can indicate where it is most cost effective to use a given technology, but cannot give specific designs for each different location.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Concluded)

LIST OF ILLUSTRATIONS

LIST OF TABLES

SECTION 1

INTRODUCTION

The United States Navy Energy Office through the U.S. Navy Energy Plan (Reference 1) has defined objectives designed to lead to energy self-sufficiency for Navy shore facilities. Several of these objectives are to: (1) test and evaluate energy systems to promote self-sufficiency and/or reduce the demand for liquid hydrocarbons, (2) utilize, where available, renewable energy sources such as geothermal, wind and solar, and (3) develop guidelines and decision criteria to implement base-wide self-sufficiency systems.

In support of this effort, the Navy's Civil Engineering Laboratory (CEL) at Port Hueneme, California, has undertaken an energy exploratory development program (Reference 2). Within this program, CEL is evaluating the use of alternate fuels and other forms of energy as required for the range of Naval shore activities. In concert with this, CEL also initiated efforts to determine the value of alternate energy systems to the Navy.

In today's energy climate, price and availability of conventional energy sources has resulted in considerable interest in alternate fuels and energy systems. Numerous studies and demonstrations are being sponsored to determine the technical and economic viability of these systems. The results of these efforts are providing better technical data and costing information. However, the potential impact of these systems

is still relatively unknown. Economic analysis techniques are required to estimate the value of emerging technologies to the Navy as well as the nation.

Economic analyses, of course, are not new. On the national level, for example, modelers have investigated the market penetration of a single technology to a variety of alternatives (References 3 and 4). These models are, however, usually very global dealing with large aggregate sets of data. They consider supply and demand elasticities, impacts of governmental policy and, in general, model the interrelationships between the economy and competing energy technologies. Only recently have modelers characterized in any detail a given energy system, its relationship to a specific demand, and possible constraints imposed by environmental regulations.

One approach that considers these factors has been proposed by Shugar, et al. (Reference 5) specifically for the Navy shore establishment. Their approach recognized the importance of accurately modeling a given technology in terms of site specific energy demand and system efficiencies as well as other site specific factors like environmental regulations, local weather conditions and land availability. They also realized the importance of integrated systems in modeling the decisionmaking process. No one technology will serve the variety of energy requirements within the operating sphere of the Naval shore establishment or even at a given Navy base. Competition between emerging technologies and conventional sources will naturally occur.

Their modeling approach was to look at individual Naval bases and determine the most cost-effective combinations of conventional and emerging technologies. They proposed then to sum the results on an

individual basis providing the necessary information. The optimization scheme they chose is based primarily on economics, but is also constrained by amounts of purchasable commercial energy. Mathematically the technique they chose was linear programming.

The objective of this study was to conduct a survey illustrating the potential impact of emerging technologies on the energy use within the Navy shore establishment. This involved developing a survey methodology, collecting the necessary input data and performing a preliminary survey for the entire shore establishment.

Our efforts in developing the survey methodology are described in Section 2. We sought a methodology which would deal with disaggregate energy use, cost and environmental factors in addition to simulating the decisionmaking process. This was accomplished by first reviewing the technique proposed by Shugar, et al. (Reference 5) and making minor modifications. The advantages and disadvantages of this technique are described in Section 2. Also included is an overall problem statement, mathematical description of the optimization scheme, annualized costing assumptions and, finally, a summary of the overall methodology.

A key element of the methodology was the modeling of the conventional and alternate energy systems. Characterization of these systems is described generally in Section 3. We modeled a total of 17 systems spanning a range of energy sources -- from renewable sources like wind, solar, and refuse derived fuels to conventional sources utilizing advanced conversion technologies. Examples of advanced systems included fluidized bed combustion and cogeneration. It was our goal to estimate as accurately as possible technical and cost information for

these systems. This information is broken down in detail for each system in Appendix A.

Another important element of the methodology was to project energy and other requirements by assembling end use data and site specific factors. We investigated the energy data currently available on Navy energy use and tried to disaggregate the data as much as possible. These efforts are described in Section 4. Other energy related site specific factors such as land availability, local weather, coal costs and availability were also collected and catalogued. The various assumptions made in handling and modeling these data are also delineated in Section 4.

The remaining sections give preliminary results for various base cases as well as present conclusions and recommendations. An analysis of the top ten Navy users of energy was completed. These results are summarized in Section 5 and discussed on an individual basis in Appendix B. Additional bases were also selected and along with the results of the top ten provided the basis for estimating the impact of alternate energy sources for the Navy shore establishment. The results of this survey are presented in Section 6. Conclusions and recommendations resulting from our efforts in this program are itemized in Section 7.

SECTION 2

METHODOLOGY

This section describes the survey methodology developed to define the optimum mix of conventional and emerging energy technologies for the Navy shore establishment. We placed three primary constraints on the development of this methodology. First, the technique had to handle disaggregate energy use data. To a certain extent, the Navy shore establishment (restricted to shore based facilities) can be viewed as a microcosm of the nation with energy requirements ranging from residential heating to industrial use of process steam. We strongly felt that the only way the technique would be successful was to disaggregate the data into well-defined energy use sectors. Within these sectors appropriate technologies could then compete.

Secondly, we placed a strong emphasis on developing as accurately as possible technical and cost information on emerging technologies. This time consuming effort resulted in detailed information on system efficiencies, total system costs (including operating and maintenance costs), and environmental factors. It also yielded information on exogenous factors such as land availability, local insolation and wind data, and fuel supply and associated costs. Again the success of the entire methodology depended strongly on the availability and accuracy of this information.

Third, it was clear that some sort of optimization scheme was required to simulate the decisionmaking process. We assumed that this process was based solely on economics; namely, the combination or mix of technologies yielding the lowest cost was the best.

How these three constraints were implemented is the subject of this section. Section 2.1 outlines the overall strategy in developing the methodology. A brief problem statement is provided along with our reasons for selecting a nonlinear programming algorithm. The optimization model is mathematically detailed in Section 2.2. A summary of the overall methodology is discussed in Section 2.3.

2.1 OVERALL STRATEGY

The Navy is a diverse and large consumer of energy. The Navy shore establishment consumes approximately 0.4 percent of the total national energy demand. In FY77, the Navy's demand was estimated to be close to 160×10^{12} Btu. Over half of this demand was for electricity, the remainder encompassing fuel oil and natural gas (Reference 2). Energy requirements are needed for family housing, office buildings and a variety of industrial activities ranging fom machine shops to major ship rework facilities. The Navy shore establishment, therefore, represents a large integrated user of energy.

Geographically, the shore establishment is spread throughout the world with the majority of the bases located in the contiguous United States. Within the United States there are 125 geographic locations which range from small space surveillance stations to large complexes, like Sewells Point, which perform a multitude of services.

The strategy was to build a methodology capable of handling such a large, diversified energy user. In the following section, a problem

statement is presented. This is followed by an outline of the selected methodology and the reasons for selecting this approach.

2.1.1 Problem Statement

The purpose of this study, as previously mentioned, was to estimate the economic value of alternate energy sources to the entire system of Navy shore facilities. The problem is stated visually in Figure 2-1. On the left hand side of the figure, the Navy is represented as an integrated user of energy. Various activities within the shore establishment require specific energy. The demand for this energy depends upon the activity or use and often varies hourly as well as daily and monthly. On the other side of this figure are various energy sources and conversion systems capable of supplying the various demands. What was desired was an optimum match of the energy demand and a set of alternate and conventional energy sources which would meet this demand.

One could envision, for instance, a variety of systems competing to supply the total or more appropriately a small subset of the total demand. Solar heating might supply domestic hot water during periods of adequate insolation, whereas a conventional steam generating system could be used as backup as well as the main source for supplying process steam. This brings up the problem of deciding which energy source or mix of energy sources is most economical in supplying a particular demand.

The costs of energy sources can be broken down into various components like initial capital costs, and operating and maintenance costs. To varying degrees, these costs are dependent on a variety of site specific factors ranging from local weather patterns, fuel availability and environmental regulations to site construction factors like soil conditions and area available for siting. Similarly, energy conversion

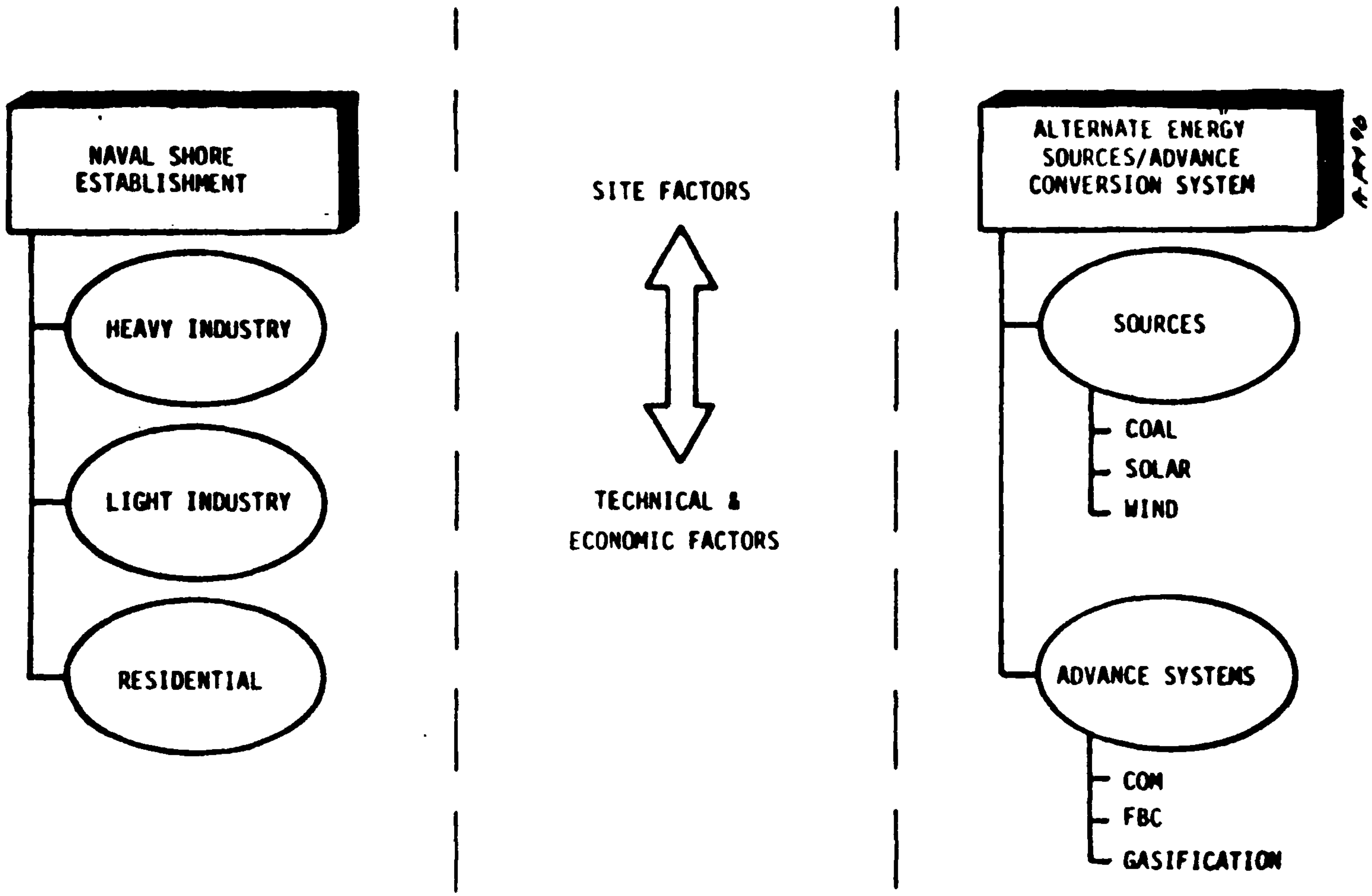

Figure 2-1. Problem statement.

depends on these parameters. This is especially true for solar and wind conversion systems, but it also applies to more conventional systems.

The problem, therefore, is not only how to best match the demand requirements but also how to identify technical and site factors which affect the overall economics.

An example of the information required to perform such an economic optimization process for a typical Navy facility is illustrated in Figure 2-2. The Mare Island Naval shipyard located in the San Francisco Bay area requires steam for industrial uses as well as for space heating and domestic hot water. Space heating and domestic hot water needs are also met using fuel oil and natural gas systems. Electricity is used throughout the base for numerous activities -- machine drives, lighting, air conditioning, etc.

To determine the optimum match, it is necessary to disaggregate energy use data as much as possible. In this way appropriate technologies can compete within these identified energy use sectors. Furthermore, since the performance of alternate sources depends on site factors, these must be identified and the information collected and catalogued. Similarly, technical and cost factors for each competing system must also be identified and the information collected and catalogued.

Finally, once all these data are assembled, a methodology needs to be developed to handle all this information in addition to providing some rationale for deciding which systems or combination of systems are most cost effective. This is the subject of the following section.

2.1.2 Modeling Philosophy and Approach

There are several approaches for dealing with the problems developed in Section 2.1.1. However, one of the key elements in any

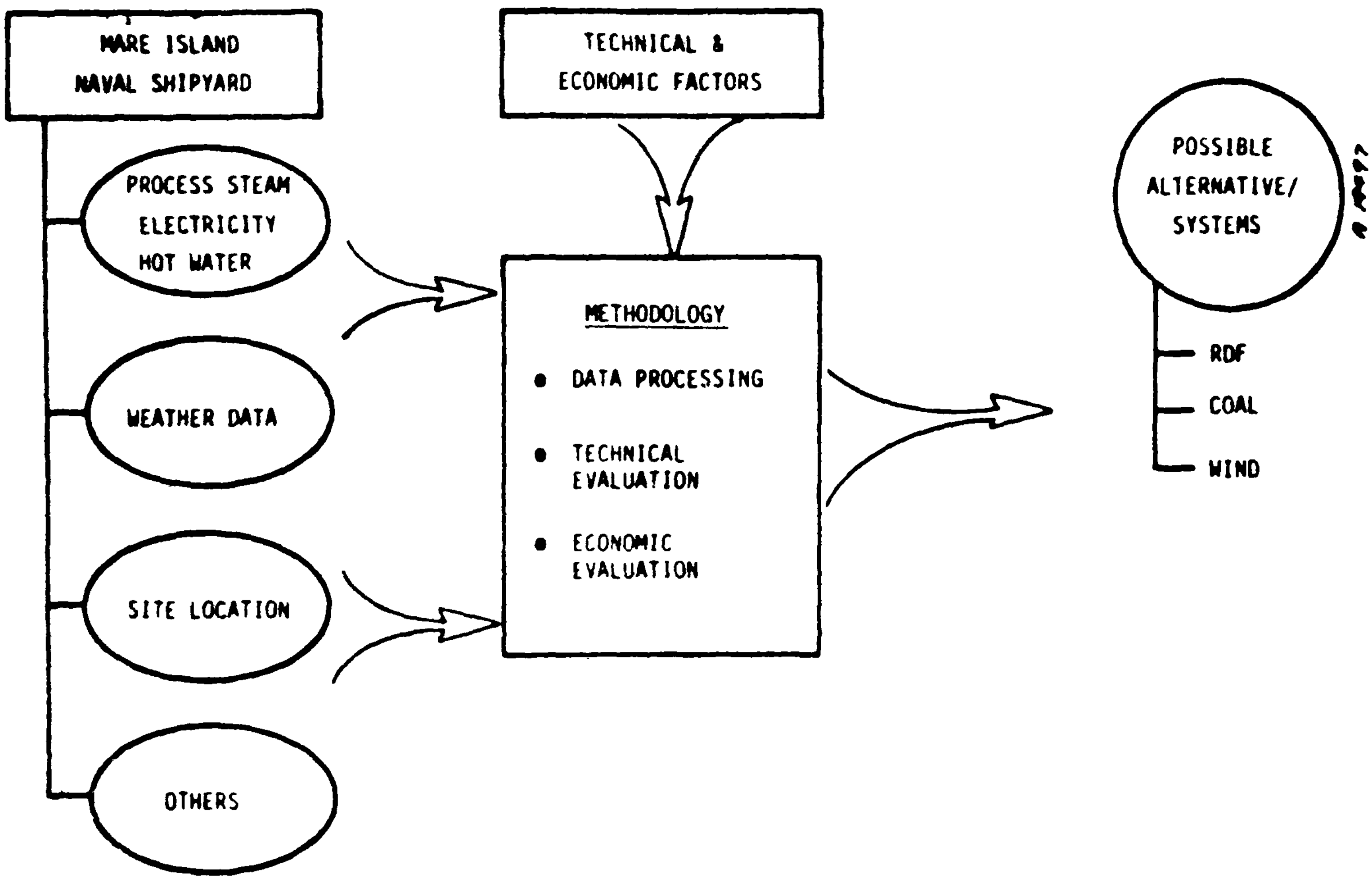

Figure 2-2. Facility example-heavy industry.

approach is how one models the decisionmaking process. It was our underlying assumption, as well as that of Shugar, et al. (Reference 5), that the best approach was to deal strictly on economics. This is the basis of current Navy procedures as discussed in Reference 6.

As pointed out by Reference 7, this assumption might be too limiting in the residential sector if the decisionmaking process involves an aggregate base of consumers. Further, the assumption might also be slightly incorrect for the Navy considering the political climate surrounding several alternatives. Nevertheless, it was not our aim to model these factors, but rather to leave such considerations to the decisionmaker.

Also, we did not consider the effects of governmental policy -- like investment tax credits, accelerated depreciation or fuel surtax. These factors, although important in the private sector of our economy, are not appropriate for the Navy.

In recent years there have been a number of energy models developed. Simplistically, these models can be divided into two generic classes: top down and bottom up. Top down modeling refers to those techniques which deal with aggregate data. They consider supply-demand relationships for pricing and, in general, capture the aggregate effect of various scenarios without detail modeling the individual factors which make up these scenarios. Bottom up modeling, on the other hand, attempts to disaggregate data into individual elements which have similar characteristics.

Top Down Modeling

Top down modeling can also be thought of as a macro-economic approach. The so-called equilibrium models (Reference 4) are examples of

models which fall into this category. These models simultaneously consider energy production, distribution and use, generally on a national scale. The models range in complexity from single to multiple technologies. The economy can be divided into various sectors depending on the complexity and emphasis of the modeling scheme. One example might be the transportation sector. Obviously, this sector is extremely diverse and complicated, including all types of fuel use from cars to buses to airplanes. Top down modeling aggregates these data and deals with the data only in this form. Subelements are, therefore, not modeled; neither are the individual decisions which might occur within these subelements.

An approach which parallels top down modeling was briefly considered as an alternative to the methodology suggested by Shugar, et al. Conceptually, one could divide the Navy into various energy demand sectors. These sectors could be grouped according to a particular Naval activity (like a Naval Air Rework Station or Naval Supply Station). It further could be assumed that these activities are relatively independent of location -- variations in demand being more dependent on the particular activity.* In this way, the Navy shore establishment could be considered in its entirety instead of dealing with individual bases as Shugar, et al. proposed.

However, even with this approach, we would not have attempted to model supply-demand relationships and price elasticities. We would have assumed that fuel prices, for example, are determined by such a

*The demands could also be modified as required for location by regionalizing parameters such as fuel costs, availability, or even weather conditions.

relationship but would have considered them as inputs to the methodology. Strictly speaking, then, this alternative would only be top down in the way the energy demand data was handled. Also, we would not have attempted to model the entire energy process associated with a given activity. Again, this would differ from the equilibrium models where energy production, distribution and use are all considered.

The basis of comparison then between the proposed top down modeling and Shugar, et al.'s approach is in how one constructs the energy demand sectors. Is it better to disaggregate the energy according to ultimate end use or handle the data in more aggregate form according to activity? There are advantages and disadvantages to both approaches. However, we felt that the best approach was to follow Shugar's intent of considering individual Navy bases and dividing the energy demand sector into end use categories.

Our rational for taking this approach is as follows. Generally, the various activities have common requirements like space heating and cooling. Therefore, the demands for a particular end use (e.g. steam) could be spread across many activities. Further, many Navy bases support several activities and often energy for these activities is supplied from a central distribution system. In fact, the Navy supplies energy according to need and not activity even though various activities might have specific energy requirements.

Another limiting factor with the top down approach is modeling those technologies which are strongly dependent on local conditions. Both solar and wind .cems fall into this category. Accurately representing these technologies requires local insolation and wind levels. The top down approach could deal with this by regionalizing but the actual details

would be smeared across activities. In the aggregate, the approach would correctly estimate the penetration of these technologies whereas details regarding location would be lost.

Bottom Up Modeling

The primary advantage of a bottom up approach is that uses of energy are disaggregated according to characteristics which have the most impact on the costs of alternate technologies. It has become common practice to express alternate technology costs as $\$/10^6$ Btu. These costs correctly account for life cycle costing including initial capital cost, operating and maintenance costs as well as the cost of money. However, comparisons of these costs are only valid when the alternatives compete for the same end use demand. It makes no sense, for instance, to compare the cost of electricity to the cost of a steam generating facility, if the electricity is used for lighting and the steam used for an industrial process. Conversely, if both forms of energy are used for space heating, then the comparison is valid.

The key element in this approach is, therefore, segregating the demand into comparable end use categories. Alternate systems (often producing alternate energy forms) can compete in these sectors.

There are several approaches for modeling competition in these sectors. For example, one could determine the costs of all technologies competing in a given sector. The costs could then be compared simply via a table or chart. Generally, the lowest cost per delivered energy would be the best. The problem with this approach, as identified by Shugar, et al. (Reference 5), is that it often does not identify an integrated cost-effective solution. It emphasizes single technologies rather than an integrated solution that emphasizes a combination of technologies.

To avoid simple comparative economics, we considered approaches which model a mix of alternate technologies. To the best of our knowledge there are two techniques which fall into this category: (1) optimization modeling utilizing linear or nonlinear programming, and (2) market penetration models. A brief overview and comparison of these two techniques follows.

Market penetration models have recently been developed to estimate the future markets of emerging technologies (References 7 and 8). The key elements of these methodologies are:

- Model disaggregate end-use data
- Model costs and energy production of alternate systems
- Compete existing and alternate technologies in appropriate demand (end-use) sector
- Model appropriate economic, financial and behavioral factors encompassing the corporate decisionmaking process

The underlying philosophy of these models is to simulate a reasonably accurate decisionmaking process which selects one alternative over the next. Cost is the basis of this selection in both references cited.

In Reference 8 the basic methodology was built around a company's internal rate of return on investment (ROI). ROI functions (or "investment preference distributions") were developed for various target industries. These functions predict the percent of companies which would invest, for this example, in solar at a given ROI. For a given target industry, the methodology parametrically calculates the percent of process heat substituted by solar for various ROI's. This, along with the investment preference function, defines that fraction of the industry willing to invest as a function of the amount of solar substitution. This

function is then integrated to determine the expected market share for a particular industry. The methodology is fairly flexible and can account for various scenarios regarding fuel price projections and cost of systems, as well as governmental policy incentives.

A similar approach was developed by Energy and Environmental Analysis, Inc. (EEA). They built a methodology to predict the market penetration of emerging technologies in the industrial use sector of our economy (Reference 7). The key element in their approach was to develop what they called "cost frequency distributions." These distributions are composed of cost distributions of various technologies competing for a specific demand and the fraction of all potential users who would experience a given cost. For example, a technology like waste heat recovery might have the lowest cost distribution compared to other technologies, but could only be applied in certain situations. Competition between technologies is accomplished by a statistical integration procedure which selects the combination of alternate technologies yielding the lowest cost for a particular demand. This results in "nominal market shares" for a given technology. These shares are then modified to reflect behavioral lag phenomenon associated with new and/or improving (risky) technologies.

EEA's model as well as that of Reference 8 are dynamic models. They consider growth projections and increases in fuel prices over a specific time frame. These factors are, however, exogenous when compared to equilibrium models where these factors are handled endogenously.

The other alternative in bottom-up modeling is an optimization procedure using classical techniques of linear programming (LP). This technique involves the formulation of an objective function which, in this

case, would minimize the costs of delivered energy for a particular demand. This function is subject to a variety of constraints which restricts the solution depending on the limitations defined in the problem. This type of approach has been used in a variety of applications including equilibrium models (Reference 4) and economic assessments of solar energy (Reference 3).

In general, LP techniques model the technologies and associated costs in more detail than a market penetration approach. Conversely, market penetration techniques can model cost distributions or, more generally, the stochastic nature of siting alternates in a variety of different situations.* Also these approaches are usually dynamic, taking into account growth factors, retirement of capital, effects of governmental policy, etc; whereas LP techniques (at least in their simplest form) tend to be static.

Obviously, there are advantages and disadvantages with either approach. We selected the LP approach primarily because it could be used for optimizing the energy supply for a given Navy base. We presumed that adequate data in the form of end use profiles and technology costs were available. Thus, the emphasis was more on determining which technologies would satisfy a specific demand at a specific location.** Secondary output would be the impact of various technologies for the entire Navy shore

---

*This can also be accomplished with LP provided the model incorporates enough detail for a given application.

**Location is particularly important for technologies such as solar and wind for which costs are strongly dependent on local isolation levels and wind speed. To a certain extent, the market penetration approach smears this detail by dealing only with costs for a given demand.

establishment. This would be accomplished by summing the individual results for each Navy base. This was essentially the approach proposed by Shugar, et al. (Reference 5).

In the following section, the optimization model is developed in more detail. This is followed by assumptions regarding uniform annual costing and a brief overview of the entire methodology.

2.2 OPTIMIZATION MODEL

2.2.1 The Model for One Demand

As discussed in Section 2.1, the optimization model chosen for this study is based on the work of Shugar, et al. (Reference 5). This model was developed to determine the optimal mix (based on minimal cost) of alternate energy sources for a single demand. The solution of the mathematical problem was cast in such a way as to minimize computational costs, an important factor when many shore facilities are to be surveyed and sensitivity analyses are to be performed. In this section, the model of Reference 5 is reproduced for completeness, and then the necessary modifications which account for more than one demand are presented.

The mathematical model as developed by Shugar, et al., is:

Minimize: $$f(\underline{x},\underline{y}) = \sum_{i=1}^{N} c_i x_i + c_o \sum_{k=1}^{T} y_k \Delta t_k \tag{2-1}$$

Subject to: $$\sum_{i=1}^{N} a_i(t_k) x_i + y_k \geq D_k \text{ for all } k \tag{2-2}$$

$$\sum_{k=1}^{T} y_k \leq L_{max} \tag{2-3}$$

$$\sum_{i=1}^{N} s_i x_i \leq A_{max} \qquad (2-4)$$

$$x_i \geq o \text{ for all } i \qquad (2-5)$$

$$y_k \geq o \text{ for all } k \qquad (2-6)$$

where:

f = Total uniform annual cost (UAC) of the mix of alternate energy systems plus the total annual cost for commercial energy necessary to supplement base energy demand

x_i = Unknown number of alternate energy device i; e.g., number of 5kW wind turbines or solar collection system in thousands of square feet

c_i = Uniform annual cost (UAC) per unit alternate energy device i

N = Number of different alternate energy devices being considered

c_o = Uniform annual cost (UAC) per unit of escalated commercial energy purchased

y_k = Unknown rate of consumption of commercial energy during the kth time increment

Δt_k = Time increment size. For this survey, Δt_k is one hour of an average day in a month

T = Total number of time increments. For this survey, T = 24/day x 1 day/month x 12 months = 288

a_i = Performance coefficient (efficiency) for device i in time increment k obtained from estimated performance curves. Values used for each device are given in Appendix A.

D_k = Shore facility demand for energy (rate) at time increment k

L_{max} = Maximum allowable annual amount of purchased commercial energy

S_i = Acreage required for siting one unit of alternate energy device i

A_{max} = Real property acreage available for siting alternate energy devices at a given shore facility.

Expression (2-1) states that the function to be minimized is the sum of uniform annual costs of all the alternate energy devices and the commercial energy purchased. Expression (2-2) requires that the sum of the energy produced in time increment k by all the alternate energy devices and the energy supplied by commercial sources meet or exceed the demand. Expression (2-3) requires that the yearly purchase of commercial energy not exceed some maximum. Expression (2-4) requires that the acreage available at the shore facility not be exceeded by the acreage required for all the alternate energy devices. Constraint (2-5) maintains feasibility of the solution and constraint (2-6) says, in effect, that excess energy produced by alternate sources in time increment k cannot be sold to the commercial supplier.

Noting that expression (2-2) consists of 288 inequalities, Shugar, et al. (Reference 5), made the following transformation. They first solved (2-2) for y_k assuming the equality to hold

$$y_k = D_k - \sum_{k=1}^{N} a_i(t_k)x_i \qquad (2\text{-}7)$$

Then they substituted the above expression into (2-1) to get

$$f(\underline{x},\underline{y}) = \sum_{i=1}^{N} c_i x_i + c_o \sum_{k=1}^{T} \left[D_k - \sum_{i=1}^{N} a_i(t_k)x_i \right] \Delta t_k \qquad (2\text{-}8)$$

To satisfy the original constraint (2-2), the expression in the brackets is continuously monitored. When its value becomes negative, it is reset to zero.

At this point in the analysis, the unknown vector $\underline{y}$ has been eliminated from the objective function but not from constraint (2-3). Shugar, et al., used the following technique to eliminate this constraint. During the computation, if the running sum of y_k exceeds the allowable maximum amount L_{max}, the value of c_0 is assigned to be artificially high. As a consequence, the cost of purchased commercial energy becomes so high that the optimization program chooses more energy to be obtained from alternate energy sources.

The above stratagem, together with the technique described in the previous paragraph, allows the original problem to be stated free of the unknown vector $\underline{y}$ as follows:

$$\text{Minimize:} \quad f(\underline{x}) = \sum_{i=1}^{N} c_i x_i + c_0 \sum_{k=1}^{T} \left[D_k - \sum_{i=1}^{N} a_i(t_k) x_i \right] \Delta t_k \qquad (2\text{-}9)$$

$$\text{Subject to:} \quad \sum_{i=1}^{N} S_i x_i \leq A_{max} \qquad (2\text{-}10)$$

$$x_i \geq 0 \text{ for all } i \qquad (2\text{-}11)$$

This method was investigated by Cooper and Stear (Reference 9) and found to be mathematically sound. In fact, the problem can be equivalently cast as an unconstrained optimization problem by using the Penalty Function method. The new problem is still linear (though in a piecewise fashion) provided the cost and performance coefficients (c_i, a_i) are independent of the size of the system (x_i). Further, the problem remains convex which insures the existence of a global optimum solution.

To prevent the optimization scheme from requiring unrealistic purchases of commercial energy during peak demand periods, we added the following constraint to the above model:

$$y_k < Y_{max} \tag{2-12}$$

This constraint was implemented in a manner similar to that used for constraint (2-3). The value of y_k is constantly monitored. If it exceeds Y_{max}, the value of c_o is set artificially high so that the optimization scheme looks for a solution in which y_k does not exceed Y_{max}.

2.2.2 Extension of the Model to More Than One Demand

The model described in the previous section was easily extended to more than one demand by summing the objective function (2-1) and the constraints over all demands. Doing this and applying the same simplifications previously described to reduce the number of constraints gives:

Minimize:

$$f(x) = \sum_{j=1}^{J} \sum_{i=1}^{N} c_{ij}\, x_{ij} + \sum_{j=1}^{J} c_{oj} \sum_{k=1}^{T} \left\{ D_{kj} - \sum_{i=1}^{N} a_{ij}\,(t_k) x_{ij} \right\} \Delta t_k \tag{2-13}$$

Subject to:

$$\sum_{j=1}^{J} \sum_{i=1}^{N} S_{ij}\, x_{ij} \leq A_{max} \tag{2-14}$$

$$x_{ij} \geq 0 \text{ for all } i \text{ and } j \tag{2-15}$$

where j represents a given demand sector and J the total number of demand or energy use sectors. All other symbols have the same meaning as previously defined except that they are now subscripted to reflect a particular demand.

As before, the quantity in the braces must be monitored during the solution. If it becomes negative, it must be reset to zero. Further, the value of y_k and its running sum must also be monitored for each demand sector j and prevented from exceeding $Y_{max, j}$ and $L_{max,j}$.

In summary, extending the model to more than one demand sector simply involves accounting for the energy in each sector, D_{kj}, and correctly incorporating the costs and energy produced for those systems competing in the various sectors. How this model is used and our assumptions regarding system modeling, cogeneration and economics of scale are discussed below.

Except for those technologies which simultaneously supply process steam and electricity (cogeneration), all systems were characterized for only one demand. This was not a limitation of the model, but of our effort required to model many energy systems. The model could easily include, for example, systems which supply both process steam and space heating. Also, as pointed out in Section 4, we did not attempt to generalize the energy models by identifying similar component costs/performance coefficients -- instead, we choose to define these parameters on an individual system basis. Further disaggregation might be considered a viable alternative as the number of systems increase.

For systems that supply energy to more than one sector (e.g., cogeneration), the objective function (2-13) requires a separate accounting for costs within each sector. This is unnecessary since the

total costs are merely the sum of the individual components. Therefore, for these type systems only total costs were used

$$(\text{i.e., } c_{nj}x_{nj} \quad \sum_{j=1}^{J} C_{nj} \cdot x_{nj})$$

On the other hand, performance coefficients, a_{ij}, were defined for each sector.

Economies of scale were also incorporated in the formulation. This was accomplished by requiring the cost coefficients, c_{ij}, to depend on the system size, x_{ij}. Although the objective function is now nonlinear, convexity is still maintained provided c_{ij} increases as x_{ij} increases. This insures the existence of a global optimum solution. How we implemented economies of scale for individual energy systems is discussed in Section 3 and in Appendix A.

2.2.3 Computation of Uniform Annual Costs

The optimization scheme outlined in the previous sections requires calculating the uniform annual cost coefficients for alternate energy systems as well as for commercial energy. These coefficients were determined using standard economic principles as delineated below. Also, a brief description of input parameters for the cost coefficients is given.

Formulation

The total cost of a system is composed of the initial capital costs and the annual costs of operating and maintaining the system. The initial capital costs are usually one-time expenditures which occur early in a project and include materials, equipment, installation and startup costs. Conversely, operating and maintenance costs occur through the life of the system. These costs include materials, labor, and replacement costs as well as fuel costs. Equating both of these cost elements requires converting the costs to an equivalent basis.

The uniform annual cost technique is one method of converting costs to an equivalent basis. Basically, this method converts all capital and operating costs to an annual basis accounting for the time value of money. Future expeditures are discounted to their present worth. Mathematically, the net present value (NPV), having constant annual costs (C), can be expressed as:

$$NPV = C \sum_{n=1}^{N} \left(\frac{1}{1 + r}\right)^{n} \tag{2-16}$$

where

r = discount (interest) rate

N = total number of time periods or system life.

This equation can be simplified by expanding the summation and substituting. This results in:

$$NPV = C \left[\frac{(1 + r)^{N} - 1}{r(1 + r)^{N}} \right] \tag{2-17}$$

The inverse of the term in the brackets is the capital recovery factor. It is equivalent to the summation above and accounts for the yearly increase in the value of money over the system life.

A similar derivation can be formulated when the annual costs are expected to increase by a fixed percent yearly. This is important especially with the rapid escalation of conventional fuel prices. If υ is the differential inflation rate and r the discount (interest) rate, then

$$NPV = C \sum_{n=1}^{N} \left(\frac{1 + \nu}{1 + r}\right)^{n} \qquad (2\text{-}18)$$

Again, this can be simplified as above giving:

$$NPV = C \left\{ \frac{r + \upsilon}{r - \upsilon} \left[1 - \left(\frac{1 + \upsilon}{1 + r}\right)^{N} \right] \right\} \qquad (2\text{-}19)$$

Strictly speaking, equation (2-19) is only valid for the case where $r > \nu$. If $r = \nu$, then net present value is simply N.

These equations are used to express the total costs (i.e., life cycle costs) of a system in terms of uniform annual costs. This is done by accounting for all costs on an annualize basis; i.e.:

$$C = \frac{1}{b_N} \left[\left(\begin{matrix} \text{Initial} \\ \text{Costs} \end{matrix} \right) \right] + \left[\left(\begin{matrix} \text{Annual} \\ \text{Maintenance} \\ \text{Costs} \end{matrix} \right) \right] + \frac{D}{b_N} \left[\left(\begin{matrix} \text{Fuel} \\ \text{Costs} \end{matrix} \right) \right] \qquad (2\text{-}20)$$

where

$$D = \left(\frac{r + \upsilon}{r - \upsilon}\right) \left[1 - \left(\frac{1 + \upsilon}{1 + r}\right)^{N} \right]$$

$$\frac{1}{b_N} = \left[\frac{r(1 + r)^N}{(1 + r)^N - 1} \right] = \text{capital recovery factor}$$

The above formulation is standard and assumes that the uniform annual costs are applied at the end of each period, *n* (Reference 10). The Navy, on the other hand, recommends that average or mid-year factors be used (Reference 6). The rationale for this is twofold:

1. Generally after the initial investment, many of the costs are spread out throughout a year; e.g., labor or operating costs to operate and maintain the system.
2. The exact times of occurrence of one-time costs in the out years is not known for sure. These costs could occur at any time during the year, not necessarily at the end of the year. Thus, averaging tends to smear out potential errors of one-time investments made at other than the end of a period.

The differences in these two approaches are shown in Table 2-1. The year end values for the capital recovery factor and the inflation-discount factor are as defined in equations (2-17) and (2-19), respectively. The averaging values were derived in a similar matter except that the initial summations were modified as follows:

$$b_N = \frac{1}{2}\sum_{n=1}^{N}\left[\left(\frac{1}{1+r}\right)^{n-1} + \left(\frac{1}{1+r}\right)^{n}\right] \tag{2-21}$$

$$D = \frac{1}{2}\sum_{n=1}^{N}\left[\left(\frac{1+\upsilon}{1+r}\right)^{n-1} + \left(\frac{1+\upsilon}{1+r}\right)^{n}\right] \tag{2-22}$$

where D is the inflation discount factor and accounts for escalation of fuel prices above the normal interest rate.

The uniform annual costs can then be calculated using equation (2-20) by correctly applying the average values in Table 2-1 instead of the year end values.* Equation (2-20) can also be used for calculating

*The current version of the NES code uses year end values: i.e., equation (2-20)

TABLE 2-1. COMPARISON OF YEAR END AND AVERAGE ECONOMIC FACTORS

Parameter	Year End Formulation	Averaging Formulation	Ratio (Avg/year end)
Capital recovery factor $(1/b_N)$[a]	$\frac{r(1+r)^N}{(1+r)^N - 1}$	$\frac{2}{2+r}\left[\frac{r(1+r)^N}{(1+r)^N - 1}\right]$	$\frac{2}{2+r}$
Inflation-discount factor[b]	$\frac{1+\nu}{r-\nu}\left[1 - \left(\frac{1+\nu}{1+r}\right)^N\right]$	$\frac{2+r+\nu}{2(r-\nu)}\left[1 - \left(\frac{1+\nu}{1+r}\right)^N\right]$	$\frac{2+r+\nu}{2(1+\nu)}$

where:

ν = differential inflation rate
r = discount (interest) rate
N = total number of years

[a]In the terminology of Reference 6, b_N is the discount factor (cf. equation 2-16)

[b]Defined as $\sum_{n=1}^{N} \left(\frac{1+\nu}{1+r}\right)^n$ for year end and $\frac{1}{2}\sum_{n=1}^{N} \left(\frac{1+\nu}{1+r}\right)^{n-1} + \left(\frac{1+\nu}{1+r}\right)^n$ for averaging.

the cost coefficients for commercial energy. In this situation, equation (2-20) reduces to:

$$C = \frac{D}{D_N}\begin{bmatrix}\text{Fuel}\\ \text{Costs}\end{bmatrix} = \frac{D}{D_N}\left[c_{oj}\right] \tag{2-23}$$

Input Parameters and Assumptions

Recall that the cost coefficients, c_{ij}, are required for each alternate system. This implies that the initial, annual maintenance, and fuel costs must be determined for each system. These costs are estimated as outlined in Section 3. The detail costs are broken down in Appendix A.

The other parameters required for the cost analysis are the discount rate, differential inflation rate, and assumed time frame for the analysis. In the formulation presented above, we have assumed that economic analysis starts at a base year, 0, and continues for N years. If the base year is different than year zero for the economic analysis, then the individual cost components have to be inflated according to $(1 + r)^n$ or $(1 + \upsilon)^n$.

In applying this methodology we took 1977 as our base year. This year was selected because the majority of the cost data for the various systems as well as commercial energy costs were reported in real 1977 dollars. The analysis was assumed to start in 1985; thus, all costs were inflated to this time and then discounted or inflated/discounted over the system life.

The economic life for this study was 25 years. This is the Naval Facilities Engineering Command (NAVFAC) guideline for utilities, plants and utility distribution systems as reported in Reference 6. This

category also includes investment projects for electricity, water, gas, telephone and similar utilities.

The Navy also provides guidelines for assumed discount and differential inflation rates. The Navy specifies a discount rate of 10 percent (Reference 6). This is essentially the average value for the private sector. The justification for using this rate revolves around the notion that Government investments are funded with money taken from the private sector through taxation. Further, these investments are made on the ultimate behalf of the private sector and, therefore, should bear a rate of return comparable to the investments made in this sector.

The differential inflation rate, as previously discussed, accounts for the expected difference between the average long-term rate and the long-term rate for a particular cost element. In our methodology, the differential inflation rate factors are only applied to fuel costs. Fuel cost escalation is expected since resources are limited and the demand is constantly increasing.* The current recommendation for differential inflation rates was obtained from the Western Division of Naval Engineering Facilities Command (Reference 11). These values are shown in Table 2-2.

2.3 MODELING SUMMARY AND OVERALL CODING STRUCTURE

The previous sections have defined the key elements in the survey methodology -- namely, the nonlinear optimization procedure and the computation of uniform annual cost coefficients. Our objective here is to summarize the entire model putting into prespective the various modeling

*The Government has strong affect on the supply-demand relationship and ultimately the future prices through regulation policies.

TABLE 2-2. DIFFERENTIAL INFLATION RATES

Fuel	% Differential Inflation Rate
Coal	5
Fuel oil	8
Natural gas and LDG	8
Electricity:	
New England States	7
Pacific Coast States	7
All others	6

elements. Subsequent sections will further define data regarding energy systems and assumptions regarding energy demand data.

Figure 2-3 illustrates the survey methodology. As indicated, various site and technical data are required. The site data, including demand data, are "preprocessed", whereas the majority of the technical impacts are handled endogenously. This approach was selected in order to minimize errors in handling the large array of site specific data, particularly hourly wind and isolation measurements. Our approach was to preprocess this data and form a smaller subset or data file that could be easily handled, thus providing a more efficient computational procedure.

The remaining portions of survey methodology were automated into a computer code -- the Navy Energy Siting (NES) code. This included programming procedures for handling the energy data file, modeling the 17 alternate energy systems considered in this study, and coding the optimization and costing previously discussed. Input and output schemes were also developed. An overall description of the code is given in Volume II of this report, Naval Energy Siting (NES), Computer Program User's Manual.

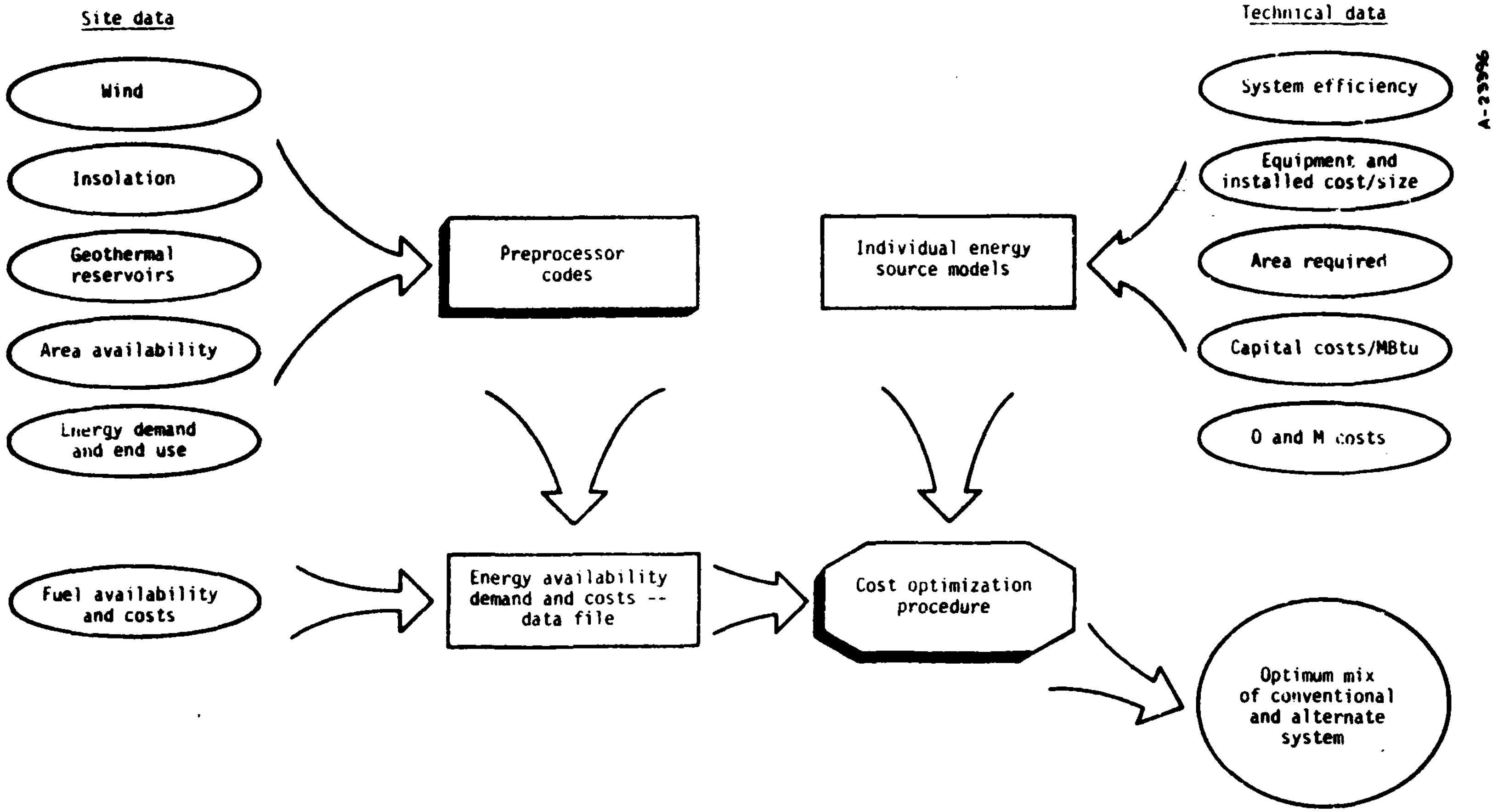

Figure 2-3. Survey methodology for given navy base.

SECTION 3

GENERAL CHARACTERIZATION OF ENERGY SOURCES

The general structure of the energy source models is illustrated in Figure 3-1. Information is passed to models as either inputs or parameters. Data required by a model that varies depending upon location (e.g., fuel cost, weather data) is labeled as inputs, whereas data that is independent of location (e.g., capital cost, maintenance cost, and conversion efficiency) is labeled as parameters. The values of inputs and parameters are entered into the computer program as input statements. Therefore, sensitivity of the optimization program to changes in these values are easily examined without modifying the code.

Given the values for the inputs and parameters, each energy source model calculates the same set of outputs: annual energy produced, uniform annual cost, and area requirements.

The following subsections describe the inputs, parameters, and outputs of the source models, and discuss, in general, the formulas used to determine outputs. The reader should refer to Appendix A for the specific equations used by each model to calculate outputs.

3.1 INPUT DATA

Input data refers to information required by the source model that either varies depending upon the particular site (i.e., insolation, coal quality), or changes during the running of the optimization program (i.e.,

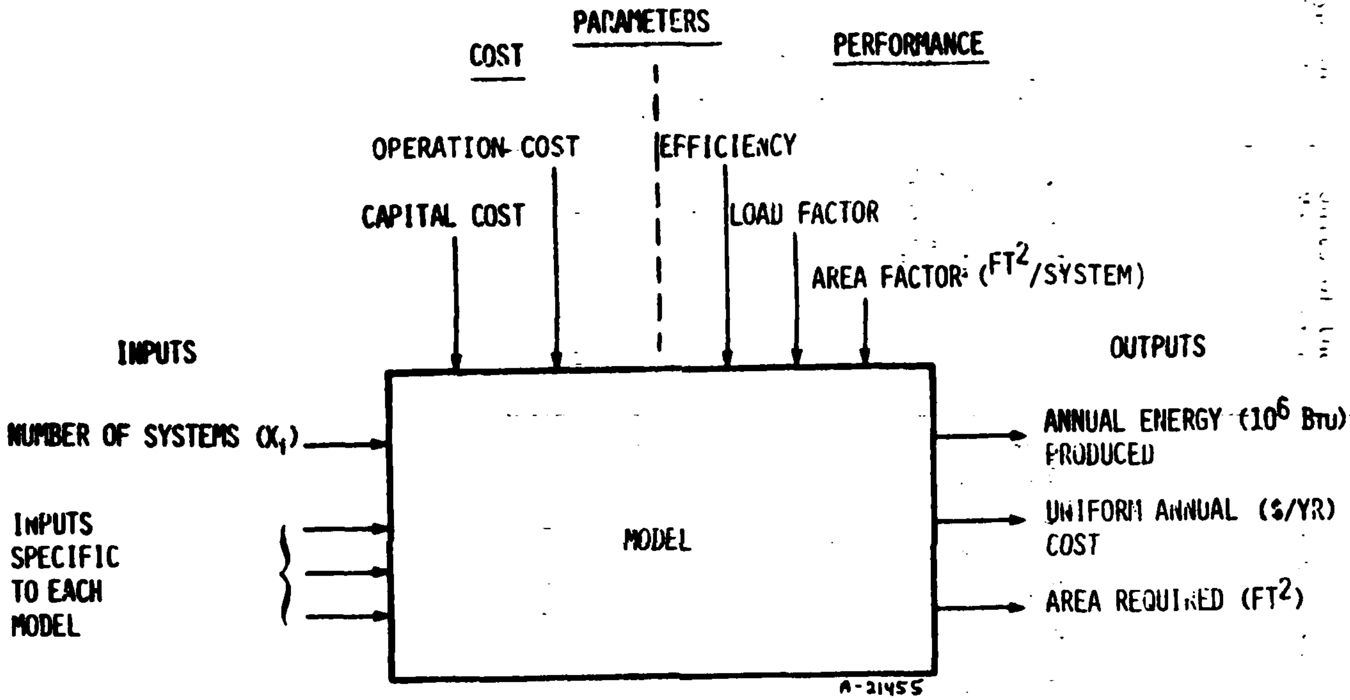

Figure 3-1. Energy source model.

the number of systems (x_i) of a particular model). Table 3-1 lists the units of the model systems, and the input data specific to each model. The size of each energy system was specified so that the energy output from a unit of any system (x_i) is approximately the same. This stipulation improves the numerical behavior and convergence of the optimization program, but otherwise is not absolutely necessary.

Insolation and wind velocity input data must be preprocessed before use by the NES optimization code. This preprocessing is discussed in Section 4.2.

3.2 PARAMETERS

Parameters refer to information required by the source model that is independent of location. Parameters are divided into two categories: cost and performance.

Cost

Economies of scale were incorporated into the capital cost of the energy conversion facility by expressing cost as an exponential function of size. Thus:

$$\text{Capital Cost (\$)} = C_f(Q)^n \qquad (3\text{-}1)$$

where:

C_f = Capital cost factor (\$/MBtu/yr)

Q = Plant size (MBtu/yr) or Annual Energy Produced/Load Factor

n = varies from 0.0 to 1.0

The capital cost factor and exponent are determined by curve fitting actual cost data to this expression. Recommended exponents are given in Reference 12. The load factor, input as a performance parameter,

TABLE 3-1. MODEL INPUTS

Type of Model	Units of the Model System	Input Specific to Particular Models
Solar Thermal	10,000 ft^2	Monthly average insolation on a tilted surface (Btu/ft^2) Monthly average ambient temperature (^oF)
Solar Photovoltaic	1,000 ft^2	Hourly insolation on a tracking parabolic trough (Btu/ft^2)
Wind	100,5 kW 200 kW 1500 kW	Hourly wind velocity (mph)
RDF (Refuse derived fuel)	(ton/day) refuse	Refuse availability (ton/day)
Geothermal	1 MW	Reservoir size (MBtu) Reservoir quality (liquid or vapor) Reservoir temperature (^oC)
Coal	(ton/day) coal	Coal availability (ton/day) Coal quality (Btu/lbm)

is defined as the fraction of time the energy conversion facility can be expected to operate relative to its maximum capability.

Operating and maintenance costs include materials, operator labor, replacement costs and the cost of fuel. These costs can be expressed in two forms:

- Function of System Capacity - The operating cost is a direct function of system size defined as the amount of processed fuel (ton/day). For example, operation cost of a RDF plant is equal to $13.95 per ton processed refuse (References 13 and 14).
- Fraction of Uniform Annual Cost - Capital costs are discounted over a 25-year system lifetime to yield a Uniform Annual Cost (UAC), as discussed in Section 2.2.3. In many cases, the operating cost of a facility is expressed as a fraction of the annual cost. For example, the operation cost of a fluidized bed combustion system is approximately 50 percent of the UAC (Reference 15). This is only an approximate technique used when actual numbers are not available.

Performance

Efficiency of an energy conversion facility is defined as the ratio of delivered energy to fuel energy input. This study assumes efficiency to be independent of systems size and location (although, in practice, larger energy systems typically have higher conversion efficiency than smaller systems). However, efficiency does depend upon fuel quality. For example, wind generator efficiency varies with wind velocity, and geothermal efficiency varies with reservoir temperature. Refer to Appendix A for more details.

Area available for constructing alternate energy systems on Navy bases is limited. Depending upon the location, area limitations may be a significant constraint on solar and/or wind energy systems. The product of the area factor and the number of systems equals the area required by a particular system:

$$\begin{pmatrix}\text{Area}\\ \text{Required}\\ \text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\ \text{Factor}\\ \text{ft}^2\text{/System}\end{pmatrix} \cdot \begin{pmatrix}\text{Number}\\ \text{of}\\ \text{Systems}\end{pmatrix} \qquad (3\text{-}2)$$

3.3 OUTPUT

Each energy source model outputs annual energy produced and uniform annual cost to the objective function in the main program. This data is used to determine the optimum mix of alternate energy systems. The uniform annual cost is calculated based upon initial capital cost, annual maintenance cost, discount rate, and system lifetime (Section 2.2.3). In addition, area required by each alternate energy system is passed to the main program. The total area required by all alternate systems constrains the objective function as previously indicated in Sections 2.2.1 and 2.2.2.

SECTION 4

ENERGY DEMAND AND OTHER SITE DATA REQUIREMENTS

The objective of this study was to determine the combination of alternative energy systems that would meet the energy demands of a Navy base at lowest cost. Information necessary to accomplish this task was divided into two categories: (1) model specific data used by the alternate energy models to calculate performance and cost (i.e., efficiency, capital cost), and (2) site specific data input to the energy models such as refuse availability and weather data. Model specific data are discussed in Section 3, while site specific data are discussed in this section.

Information required by each alternate energy model was listed in Table 3-1. In contrast to other site data, energy demand and weather data at each site vary both with season and with time of day. Consequently, weather and demand data provided on magnetic tapes were preprocessed before use by the NES optimization code. Although many energy studies overlook time variations, matching energy demand with supply is a primary factor in determining economic feasibility of solar and wind systems. Simulation of energy demand and weather (insolation and wind velocity) is discussed in Sections 4.1 and 4.2, respectively.

4.1 ENERGY DEMAND

Alternate energy systems are designed to produce only specific types of energy. For example, flat-plate solar-thermal systems are capable of meeting only low temperature thermal requirements. Therefore, it is necessary to disaggregate overall Navy energy demand into distinct energy end uses for which various energy sources can compete. End uses are determined by tracing the fuels consumed by a Navy base from purchase to end use. Initially, this study identified six distinct end uses, namely: (1) electricity, (2) space cooling, (3) hot water, (4) space heating, (5) process steam, and (6) pneumatic power.

Defense Energy Information System (DEIS-2) (Reference 16), and Utilities Cost Analysis Report (UCAR) (Reference 17) were used to trace energy from purchase to end use.* DEIS-2 lists the quantity of coal, natural gas, electricity, and fuel oil purchased each month at a Navy activity. UCAR supplements this information by identifying the energy produced and delivered on a Navy activity. Electricity, steam, natural gas, pneumatic power, and space cooling are listed in UCAR.

Unfortunately, both UCAR and DEIS-2 indicate only intermediate forms of energy, and not the ultimate energy end use. For example, although steam produced is known from UCAR, the distribution of steam among hot water heating, space heating, and process steam end use cannot be determined from either UCAR or DEIS-2. Similarly, although natural gas is used for space heating and domestic hot water, its actual distribution cannot be determined.

---

*Although the Navy is continually improving the accuracy of its energy consumption data base, some of the information presently available may be unreliable due to the diversity of reporting techniques at each Navy base (Reference 18).

Figure 4-1 shows the distribution of conventional energy sources and end uses. Information available from UCAR and DEIS-2 is indicated by solid lines on Figure 4-1. Only pneumatic power and space cooling end uses can be explicitly calculated. All other end uses must be determined using estimating techniques.

Because of the lack of adequate energy end use information, and the inaccuracy of energy end use estimating techniques, this study disaggregated energy demand into three broadly defined energy sectors: heating, process steam, and electricity (Table 4-1).

TABLE 4-1. ENERGY SECTORS

Energy Demand Sector	Energy End Use
Heating	Space heating Domestic hot water
Process Steam	Industrial steam Shaft power
Electricity	Lighting Appliances Space cooling Pneumatic power

4.1.1 Heating Demand

Heating demand includes hot water and space heating requirements at a Navy base. This demand requires low temperatures, typically less than 150°C, which is well within the capability of solar energy systems. Although hot water and space heating are incorporated into one demand, these end uses are determined using two distinct estimating techniques. These are discussed below.

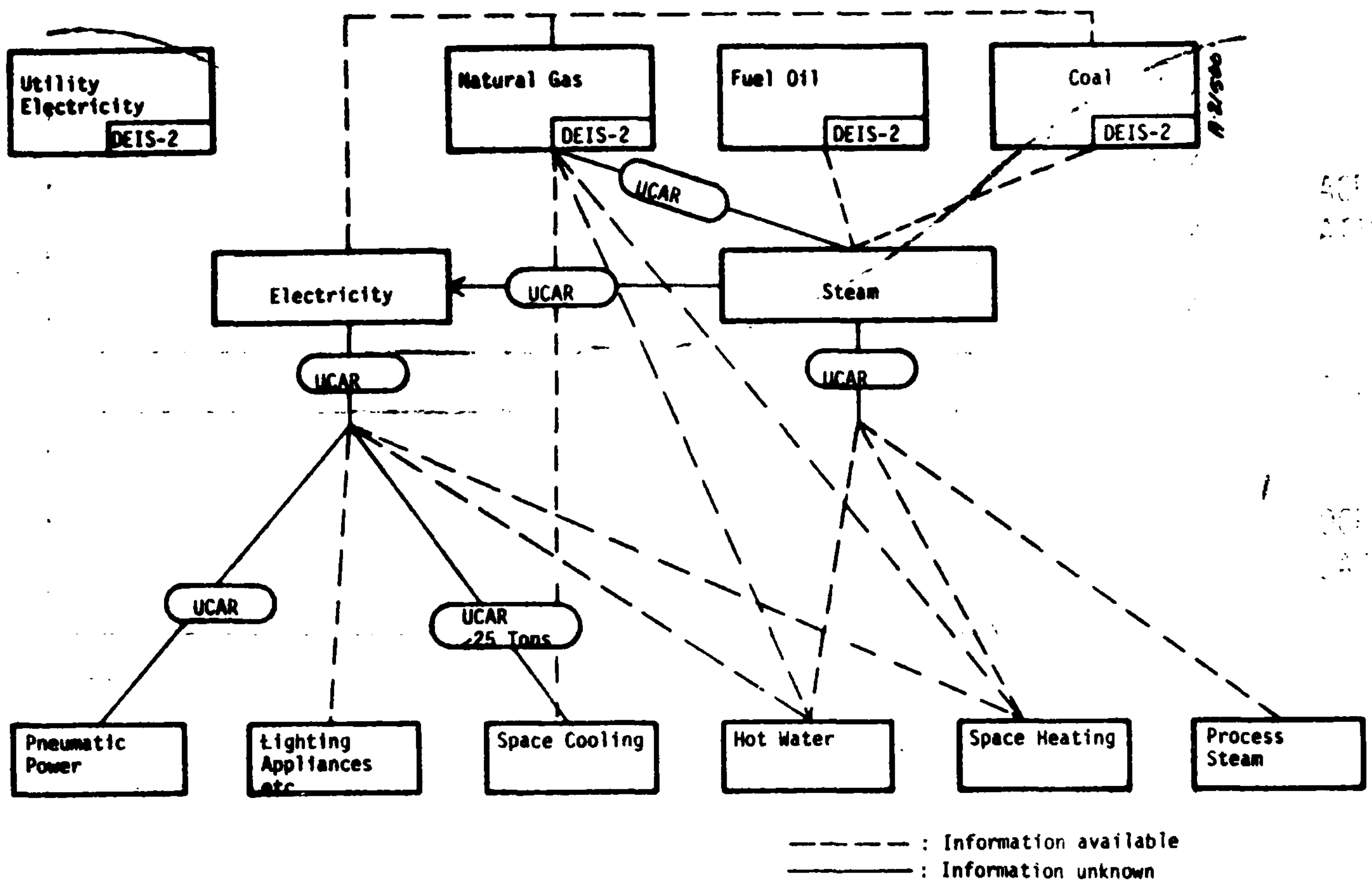

Figure 4-1. Distribution of conventional energy.

Space Heating End Use

Space heating varies monthly, but remains approximately constant on an hourly basis. A common approach to estimating space heating is to calculate the heat loss from buildings. Heat loss can be expressed as:

$$Q = h\,A\,D \tag{4-1}$$

where

h = Heat loss coefficient $\left(\frac{\text{MBtu}}{\text{ft}^2 - \text{degree day}}\right)$

A = Exposed building area (ft^2)

D = Degree days

Unfortunately, heat loss coefficients depend significantly on the type of building material (brick versus wood) and the amount of insulation. This information is not readily available from current Navy data. As a result, this study uses a more global approach to estimating space heating requirements.

Figure 4-2 illustrates a typical annual thermal energy demand profile consisting of hot water, process steam, and space heating demand (Reference 19). We assumed that hot water and process steam demand remain approximately constant throughout the year. Therefore, annual variations in thermal energy demand correspond directly to changes in monthly space heating requirements. In other words, monthly thermal energy demand in excess of the minimum monthly demand during a year is attributed entirely to space heating. Stated algebraically:

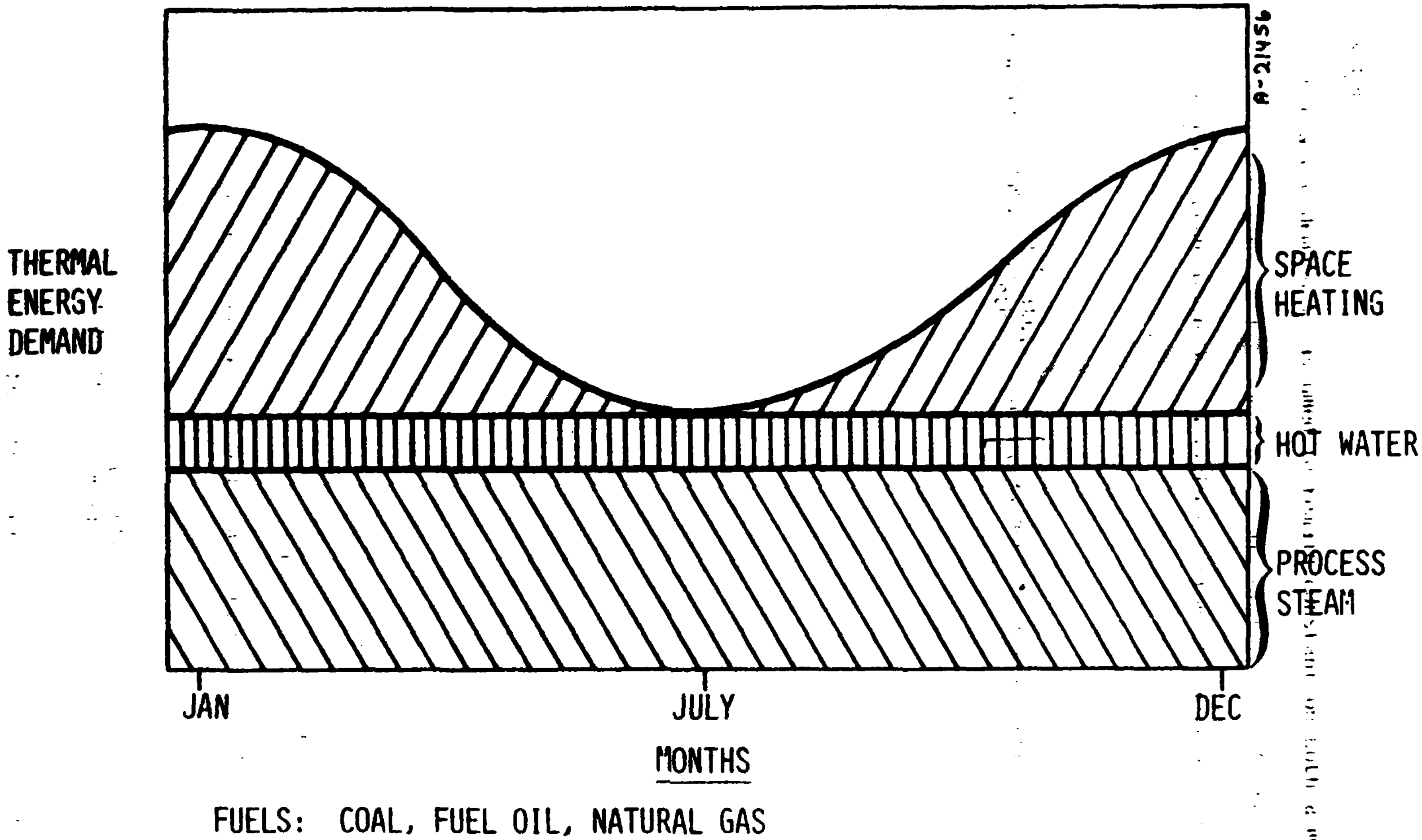

Figure 4-2. Annual thermal energy demand.

$$(\text{Space Heating})_i = TE_i - TE_{minimum}$$

where:

TE_i = Thermal energy demand during month i (10^6Btu/month)

$TE_{minimum}$ = Thermal energy demand during the month of minimum demand

Monthly thermal energy demand equals the sum of monthly fuel consumption (available on DEIS-2) converted to energy end use using typical conversion efficiencies and distribution losses. This result must be further reduced to account for the fraction of purchased fuels used to produce electricity (available on UCAR). Thus, thermal energy demand is expressed by:

$$TE_i = \eta_{loss}\left[\eta_{conv}\left[(\text{Natural Gas})_i + (\text{Fuel Oil})_i + (\text{Coal})_i\right] - F_e\right]$$

where:

i = month

η_{loss} = Distribution losses = $\frac{\text{Delivered Energy}}{\text{Produced Energy}}$

= 90 percent (i.e., 10 percent losses)

η_{conv} = Conversion Efficiency = $\frac{\text{Produced Energy}}{\text{Purchase Fuel}}$

= 80 percent (References 20 and 21)

$(\text{Natural Gas})_i$ = Consumption of natural gas during month i taken from DEIS-2 (10^6Btu/month)

$(\text{Fuel Oil})_i$ = Consumption of fuel oil during month i taken from DEIS-2 (10^6Btu/month)

$(\text{Coal})_i$ = Consumption of coal during month i taken from DEIS-2 (10^6Btu/month)

F_e = Amount of fuel used to produce electricity obtained from UCAR (10^6Btu/month)

Hot Water

Hot water demand is assumed to remain constant on both a monthly and hourly basis. Hot water demand is a direct function of the resident and nonresident population on a Navy base. From the Navy's Utility Target Manual (Reference 20) monthly hot water demand is calculated as:

$$\text{Hot Water Demand } \left(\frac{10^6 \text{ Btu}}{\text{Month}}\right) = \text{HF} \left[(\text{residents*}) + 1/4\ (\text{nonresidents*})\right] \quad (4\text{-}2)$$

where:

$$\text{HF} = \text{heating factor } \left(\frac{10^6 \text{ Btu}}{\text{person/month}}\right)$$

Hot water heating factors vary from 0.75 to 1.5 $\frac{10^6 \text{ Btu}}{\text{person/month}}$ depending on the water temperature required and the annual volume of water used (References 20 and 21). A typical value of 1.0 $\frac{10^6 \text{ Btu}}{\text{person/month}}$ was assumed for this study.

4.1.2 Process Steam

Process steam refers to the steam used for industrial purposes exclusive of steam used for space heating and hot water. Process steam demand is fairly constant on a monthly basis, but varies on an hourly basis. Therefore, the process steam demand for each month is assumed to equal the delivered thermal energy during the minimum demand month minus the hot water demand (see Section 4.1.1 and Figure 4-2):

$$\text{Process Steam Demand } \left(\frac{10^6 \text{ Btu}}{\text{month}}\right) = TE_{\text{minimum}} - HW \quad (4\text{-}3)$$

*These data were obtained either from Reference 22 or by calling the Navy Installation.

where:

$TE_{minimum}$ = Thermal energy demand during July $\left(\frac{10^6 \text{ Btu}}{\text{month}}\right)$

HW = Hot water demand $\left(\frac{10^6 \text{ Btu}}{\text{month}}\right)$

A typical hourly process steam demand profile was taken from the Battelle's Sewells Point Naval Complex Study (Reference 18) and is illustrated in Figure 4-3. Although this daily demand profile may vary depending upon seasonal industrial activity, for simplicity we have neglected this variation.

4.1.3 Electricity

As shown in Figure 4-1, electrical demand includes electricity supplied to appliances and lighting, as well as to electrical air conditioners and pneumatic power. Electrical demand varies on both a monthly and hourly basis. Monthly electrical demand is simply calculated as the sum of purchased electricity (available on DEIS-2), and electricity produced from steam generators on the Navy base. Thus, monthly electrical demand is calculated as:

$$\text{Delivered Electrical Energy } \left(\frac{\text{kW-hr}}{\text{month}}\right)_i = (\text{Purchased Electricity})_i + (\text{Produced Electricity})_i \quad (4\text{-}4)$$

for month i where:

Produced Electricity = η_{EI} Fe

η_{EI} = Conversion efficiency = 30 percent

Fe = Amount of fuel used to produce electricity -- taken from UCAR

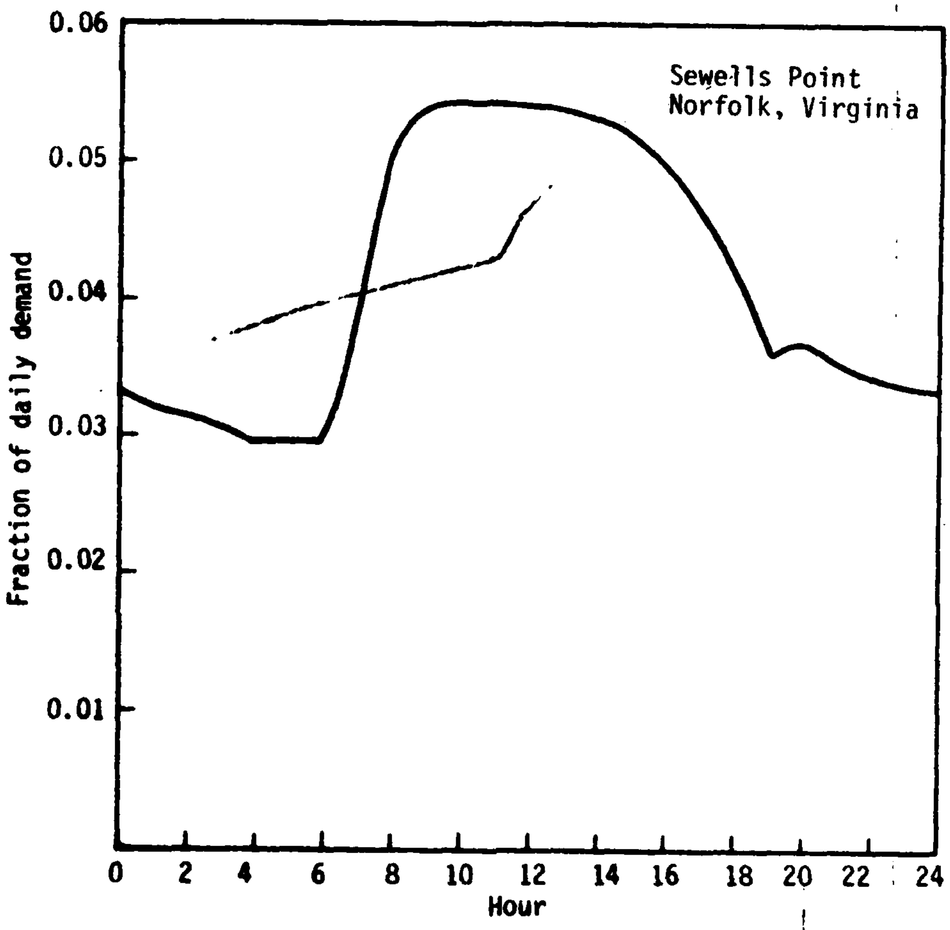

Figure 4-3. Process steam demand profile.

Navy hourly electrical demand profiles have been documented by the Naval Weapons Center (Reference 23) and by a 1977 Battelle study (Reference 15). Although this daily demand profile probably varies from winter to summer, for an initial analysis we have neglected this variation. A typical electrical demand profile is displayed in Figure 4-4.

4.2 WEATHER DATA

Accurate simulation of solar and wind energy performance requires accurate simulation of weather. Meteorological data tapes list hourly total insolation on a horizontal surface, hourly average wind velocities, and hourly ambient temperatures. This information is available from sites throughout the U.S. for various years. Insolation and wind velocity data were preprocessed to yield monthly average values from which average hourly profiles were generated. Although this procedure is not accurate for a particular hour (for example, 1200 on January 15), when used iteratively over a year, it will adequately simulate a typical year of weather. Similarly, monthly average ambient temperatures were determined and supplied as input to the solar thermal model (see Appendix A, Section A.5.2).

4.2.1 Insolation

For this study, design of the solar thermal energy system includes a simple flat-plate collector which absorbs total (direct and diffuse) incident radiation. The solar thermal model, based upon the f-chart modeling technique (see Appendix A.5.2), assumes a 1- to 2-day thermal storage capacity which allows energy output to vary independently of solar (hourly) input. As a result, the solar thermal model requires only average values of monthly insolation on a flat-plate (see Figure 4-5). For maximum absorption, flat-plates should be tilted at an angle to the

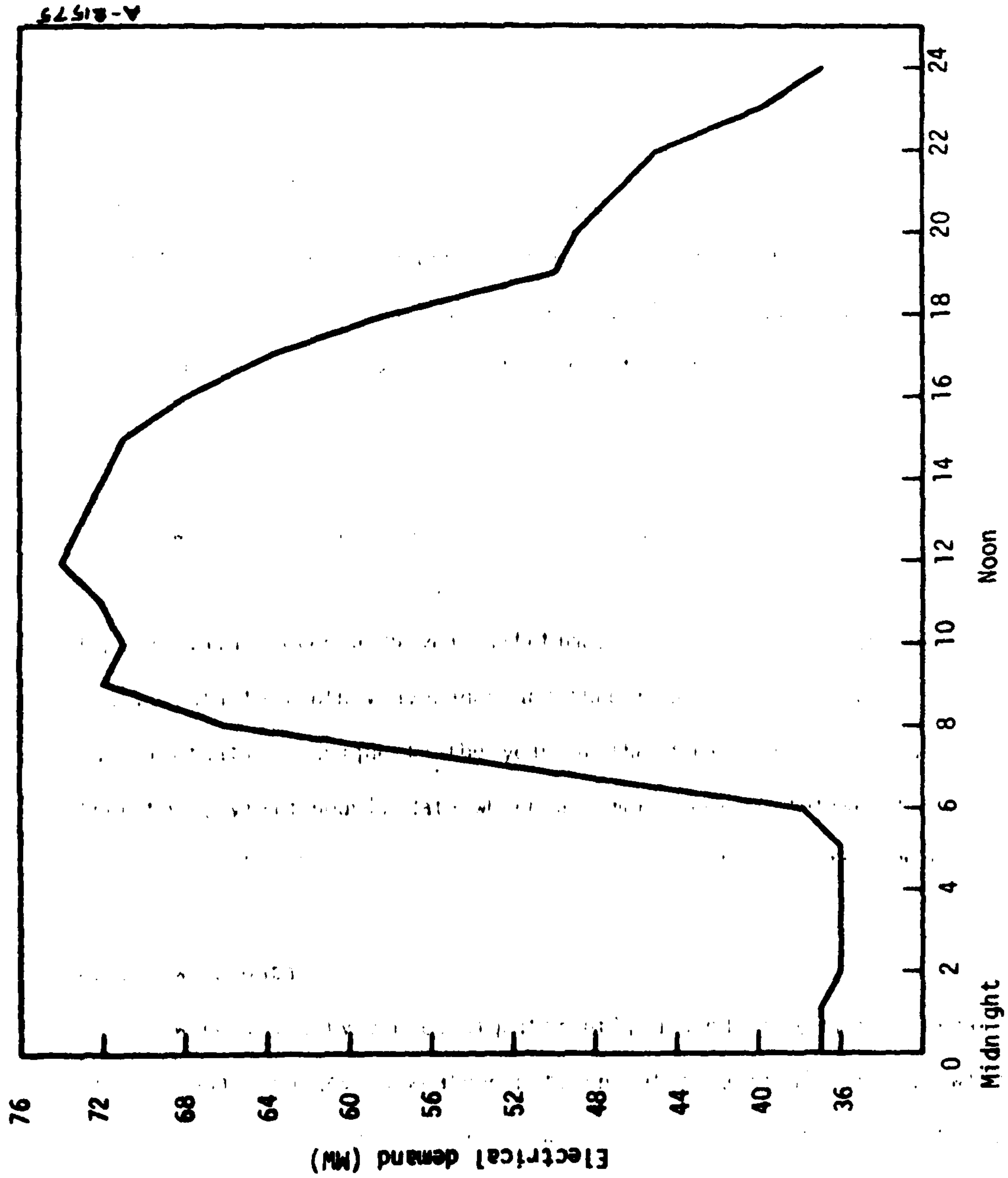

Figure 4-4. Daily electrical demand profile.

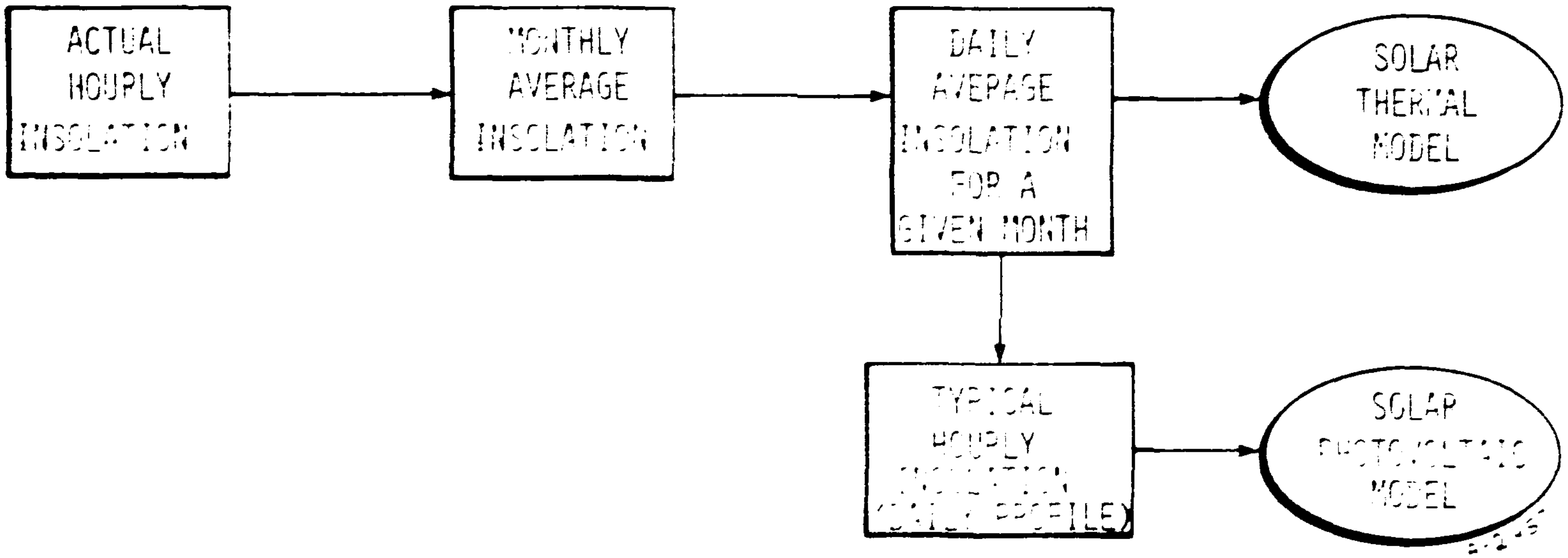

Figure 4-5. Processing technique for insolation data.

horizon equal to the latitude plus or minus 10 degrees corresponding to the winter or summer, respectively. A procedure developed by Duffie and Beckman (Reference 24) was used to convert total radiation on a horizontal surface to total radiation on a tilted surface.

The photovoltaic system consists of a concentrating collector which absorbs only direct incident radiation. Presently, no method exists for economically storing electrical energy. Therefore, in contrast to the solar thermal model, the performance of the solar photovoltaic model is strongly dependent on hourly insolation. A technique developed by Liu and Jordan (Reference 25) was used to convert monthly average insolation into the required hourly insolation. This hourly insolation profile is illustrated in Figure 4-6.

We choose not to use the actual hourly insolation data since these data are valid for only 1 year and as such do not potentially represent typical values over a 25-year lifetime. Instead, by converting the actual hourly data to monthly averages and then hourly averages we hope to dampen out fluctuations unique to the year of the data. This procedure should, therefore, yield hourly data which are more representative of an average year. Unfortunately, this approach also tends to mask the impact of cloud cover.

4.2.2 Wind Data

Wind velocity varies significantly depending upon the terrain and the seasonal changes in weather patterns at a particular site. Wind ordinarily exhibits a seasonal as well as diurnal pattern. Further, wind generator power is proportional to the cube of the wind velocity. Obviously, wind generator performance is very sensitive to simulated wind velocity profiles.

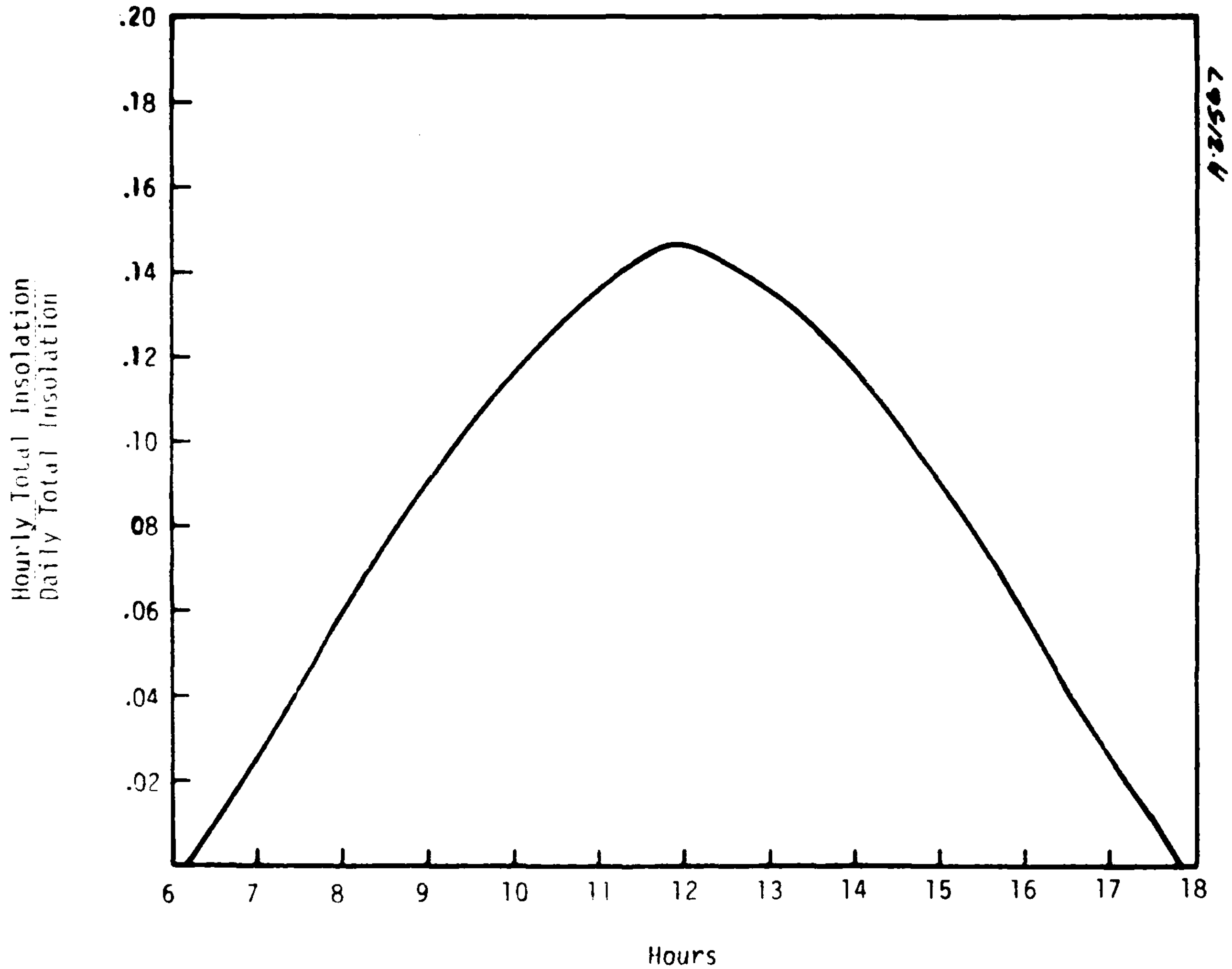

Figure 4-6. Daily total insolation profile.

Wind can be described by constructing velocity distribution curves where the average velocity and hour of peak velocity are specified as parameters for each month (Figure 4-7). A yearly distribution of wind velocities (i.e., number of hours wind velocity exceeds a given velocity) is also used. An example of an hourly distribution curve is shown in Figure 4-8. This curve was generated by distributing the corresponding annual duration curve (see Figure 4-9) about the hour of peak velocity. The curve is then adjusted so that the area under the hourly curve is equal to the average velocity.

The average wind velocity of the diurnal wind velocity profile is changed by adding incremental amounts of velocity to each hour. This allows adjustment of the velocity profile to the designated monthly average windspeed. In analytical form, this can be expressed as:

$$V_{(T_{max} + j)} = V_j + (V_i - V_{ave}) \qquad (4\text{-}5)$$

$$\text{If } V_{(T_{max} + j)} < 0, \text{ then } V_{(T_{max} + j)} = 0$$

where:

$V_{(T_{max} + j)}$ = wind velocity at time $T_{max} + j$

V_j = wind velocity at time j based upon the annual velocity distribution curve

j = $\pm$ 1 to 12 hours

V_i = monthly average velocity during month i

V_{ave} = annual average velocity

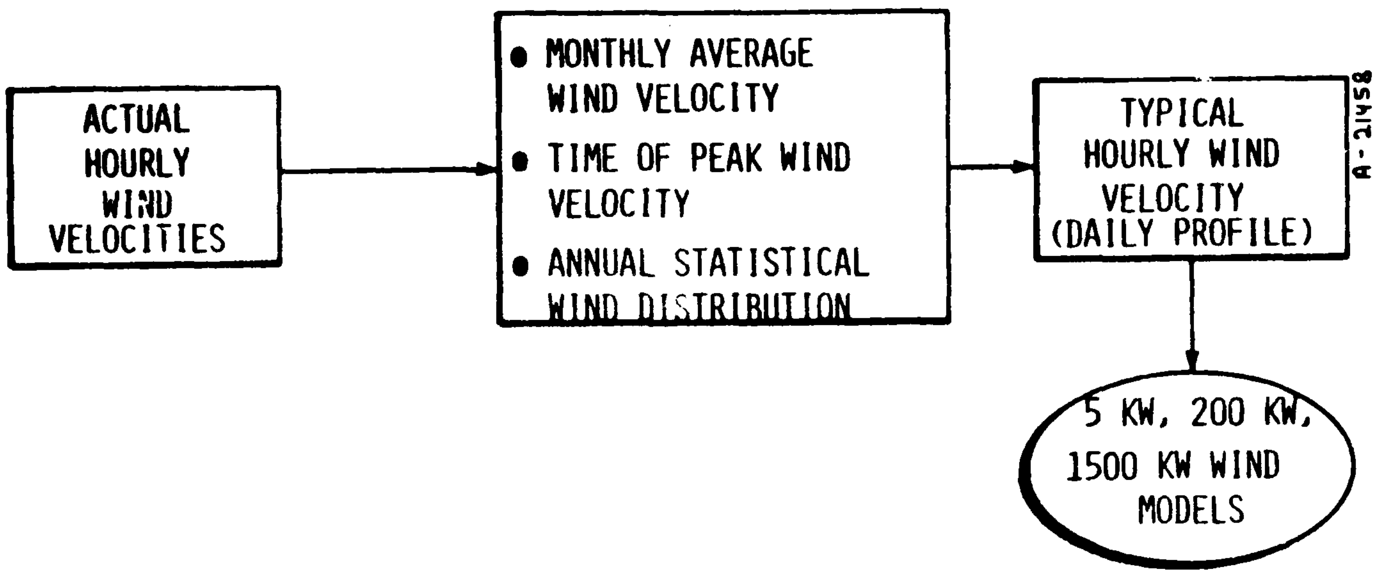

Figure 4-7. Processing technique for wind data.

For example, the average wind velocity during January may be 10 [illegible] and the average peak velocity may occur at 1600 hours. The wind [illegible]

[illegible]

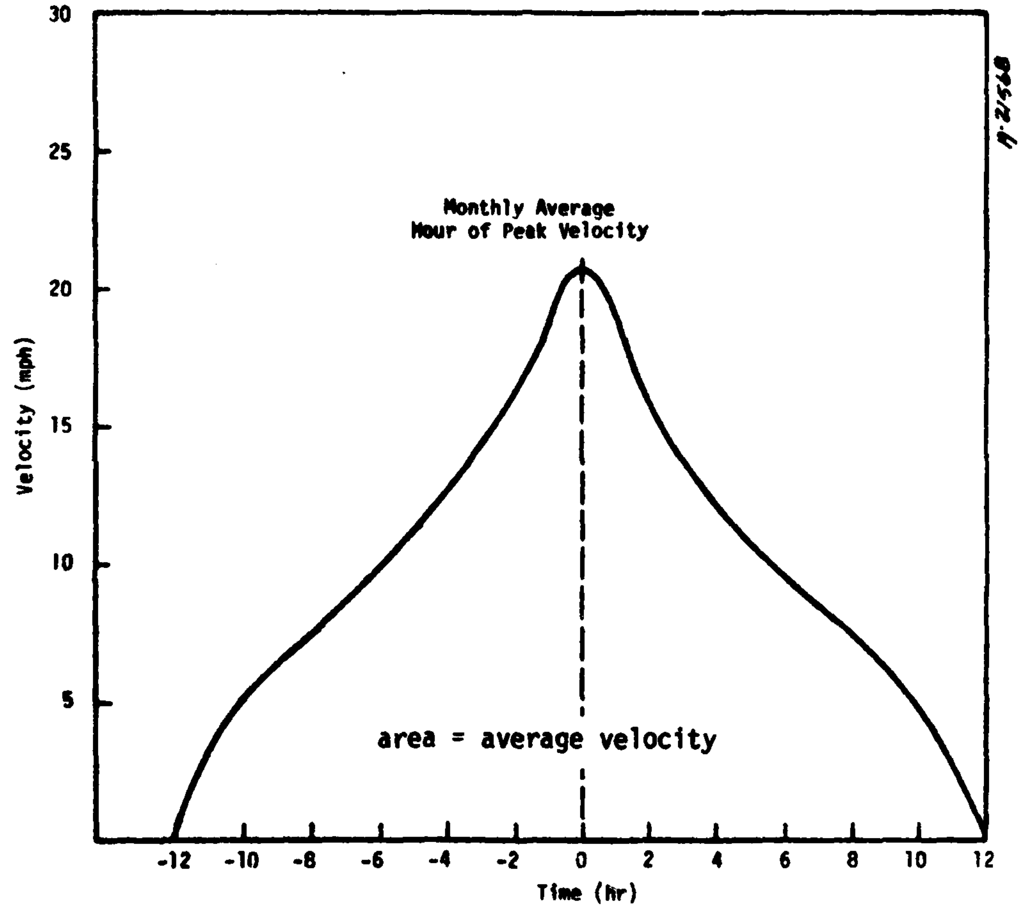

Figure 4-8. Hourly wind distribution curve.

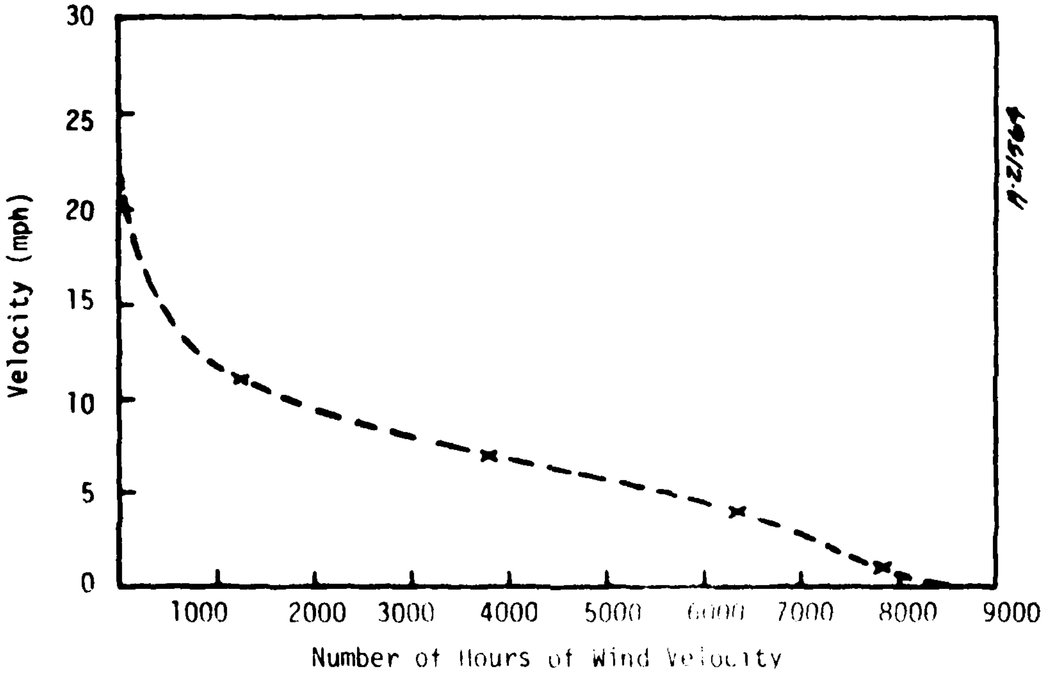

Figure 4-9. Annual wind velocity duration curve.

For example, the average wind velocity during January may be 10 mph, and the average peak velocity may occur at 1600 hours. The wind velocity, then, would be distributed symmetrically about the peak hour at the given monthly average velocity.

SECTION 5

EVALUATION OF THE TOP TEN ENERGY CONSUMERS

In the United States, there are approximately 125 Naval geographical locations situated primarily on the East, West, and Gulf Coasts. Energy consumption varies tremendously throughout these locations. For example, in FY-75, the Navy complex in Norfolk, Virginia consumed 10.9 x 10^{12} Btu/year of fuel, whereas the weapons detachment in Ft. Lauderdale, Florida consumed only 0.01 x 10^{12} Btu/year. However, a few large activities consume the bulk of the Navy energy demand. In particular, as illustrated in Figure 5-1, the 10 largest bases account for nearly 44 percent of the total energy used by the Naval shore establishment (limited to the Continental U.S., Hawaii, and Alaska).

To supplement its energy conservation program, the Navy is investigating alternate energy sources as methods for reducing energy consumption, energy cost, and dependence on petroleum fuels. Implementing alternate energy systems at large Navy bases can potentially net a significant overall reduction in conventional energy consumption. Furthermore, larger bases are able to support correspondingly larger energy systems which, due to economies of scale, can provide energy at lower cost. Therefore, siting alternate energy systems at the top ten energy consumers can realize a substantial reduction in consumption of petroleum based products as well as substantial cost savings.

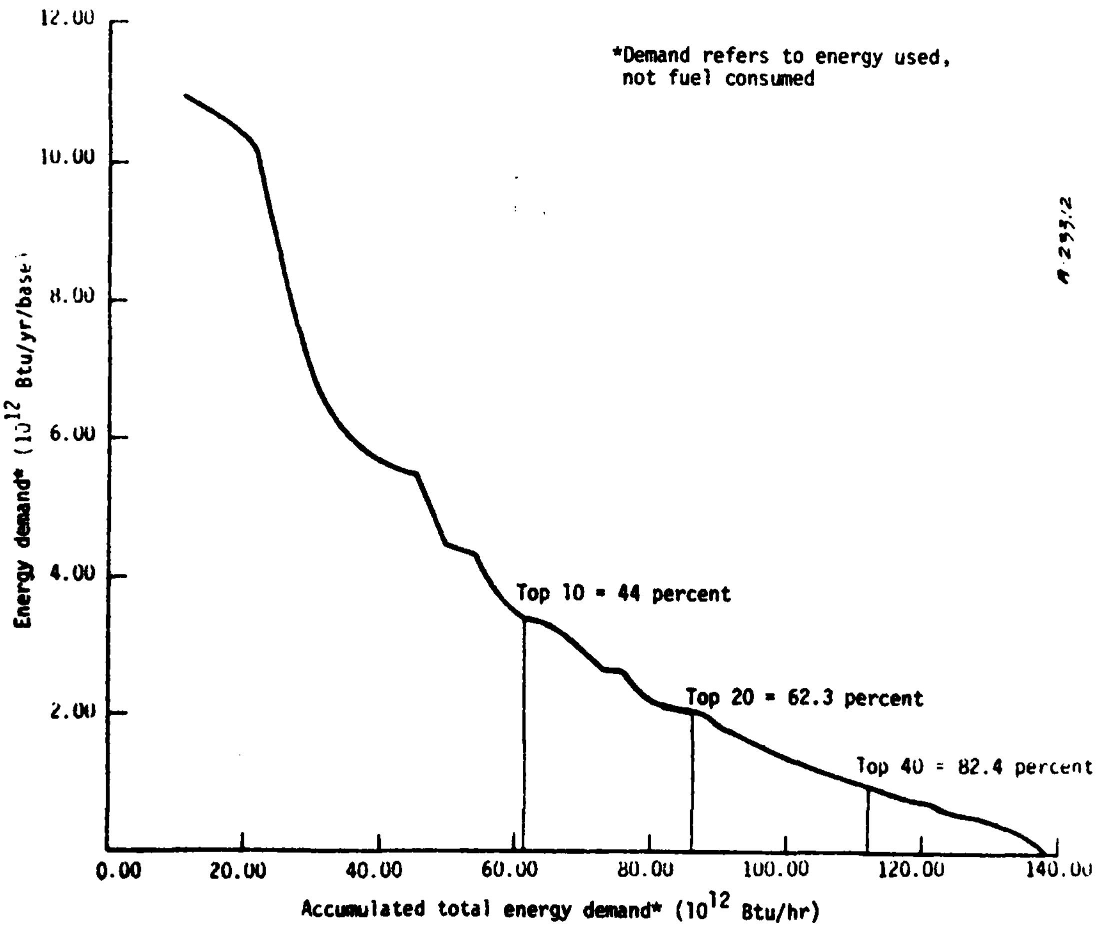

Figure 5-1. Total energy demand -- energy used, not fuel consumed -- for the Naval Shore Establishment in the United States (Reference 26).

Our objective here is to describe the results obtained from the NES computer code for the top ten energy consumers. Site data for these bases are discussed in Section 5.1 and include energy demand, energy availability, and cost data. The results are presented in Section 5.2.

5.1 SITE DATA

At each Navy base, alternate energy systems compete with conventional energy systems to meet total energy demand at minimum cost. The optimum mix of systems is determined by the NES computer program. Table 5-1 lists the alternate energy systems currently modeled in the NES code. The computer program was designed so that the user can easily expand this list of energy systems. Energy demand not satisfied by alternate energy systems is met by conventional sources: oil-fired boilers for the heating and steam sectors, and utility-purchased electricity for the electrical sector. For each of these systems, we identified fuel and land area availability, as well as capital and operating costs. These data, along with our assumptions, are further discussed below.

5.1.1 Energy Demand

Energy demand at each base was disaggregated into three end use categories: heating, process steam, and electricity. Following the procedure outlined in Section 4.1, fuel consumption (natural gas, fuel oil, coal, and electricity) given in DEIS-2 (Reference 16) was converted into energy demand. The portion of process steam used to generate electricity was determined from UCAR (Reference 17). Table 5-2 lists the energy demand for the Navy's top ten energy consumers. Note that the values given refer to actual delivered energy. Thus, heating demand was calculated by multiplying fuel consumption by 80 percent efficiency.

TABLE 5-1. ALTERNATE ENERGY SYSTEMS

Energy Use	Energy System
Heating	Refuse Derived Fuel (RDF) Fluidized Bed Combustion (FBC) Conventional Coal Combustion (CCC) Solar Thermal
Process Steam	RDF FBC CCC Cogeneration[a] Geothermal
Electricity	RDF FBC CCC Cogeneration[a] Solar Photovoltaic 5-kW Wind 200-kW Wind 1500-kW Wind Geothermal

[a]The cogeneration system consists of a coal-fired boiler which produces steam to drive a back-pressure steam turbine. Exhaust steam is used for process applications.

TABLE 5-2. ENERGY DEMAND FOR THE TOP TEN ENERGY CONSUMERS

Site	Annual Energy Demand[a] (FY 1976)			Fraction of Process Steam Used to Generate Electricity (Percent)
	Heating (10^{12} Btu/yr)	Process Steam[b] (10^{12} Btu/yr)	Electricity[b] (10^{3} MWH/yr)	
Norfolk, Virginia	2.24	1.73	524	7.2
San Diego, California	0.92	1.69	565	0.0
Philadelphia, Pennsylvania	2.74	0.78	205	16.4
Charleston, South Carolina	0.54	1.12	301	2.3
Pearl Harbor, Hawaii	0.63	0.58	330	0.0
Great Lakes, Illinois	1.58	1.04	116	2.13
Portsmouth, Virginia	0.89	0.74	206	27.7
Pensacola, Florida	0.39	1.32	163	22.8
Bremerton, Washington	0.74	0.67	153	7.6
New London, Connecticut	0.88	0.70	116	22.1

[a]Values for energy demand refer to delivered energy, calculated by reducing fuel consumption by conversion efficiency and distribution losses.
[b]Values given for steam and electrical demand reflect the conversion of process steam to electricity.

Similarly, for process steam fuel consumption was multiplied by 80 percent and 90 percent accounting for conversion efficiency and distribution losses, respectively (Section 4.1.1). Electricity is either purchased or generated using process steam. Purchased electricity involves no conversion energy loss, whereas for on-base generated electricity we assumed a 30 percent conversion efficiency.

Heating demand consists of space heating and domestic hot water demand. The procedure for estimating this demand is discussed in Section 4.1.1. Hot water demand was estimated based upon resident and nonresident populations given in Reference 22. As a first approximation, the heating demand was assumed constant on a daily basis, but to vary annually depending upon the season. As expected, heating demand is largest at northeast locales such as Norfolk and smallest at the southern locales such as Pensacola.

At Navy bases, process steam supports industrial activities such as ship and aircraft rework facilities. Consequently, steam demand at each site varies depending upon the particular activities at each base. In contrast to heating demand, process steam demand remains constant for each month but varies considerably during the day in response to the daily work cycle. Battelle (Reference 15) developed a typical daily steam demand profile based upon data given in the Navy's "Utilities Target Manual" (Reference 20). This profile, illustrated in Figure 5-2, was applied to all ten bases.

As mentioned previously, electrical power is either purchased from a local utility company or generated on-base using process steam. The fraction of process steam used to produce electricity is listed in

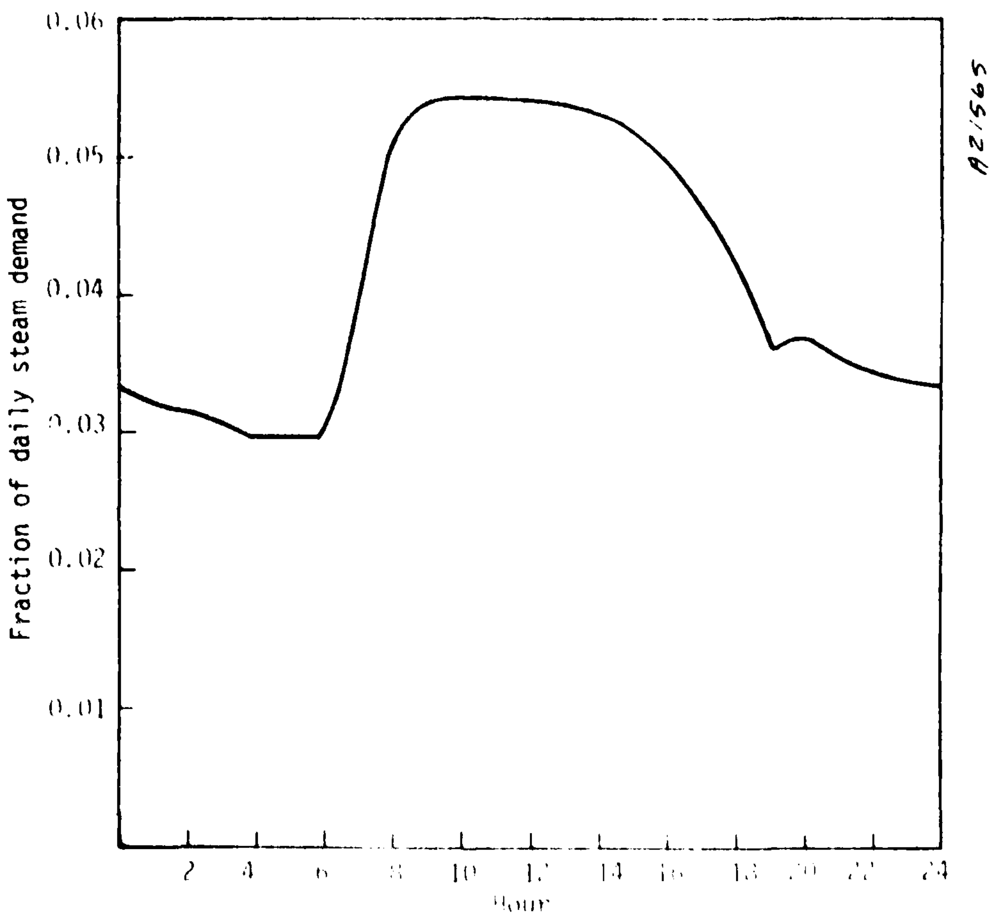

Figure 5-2. Typical process steam demand profile.

Table 5-2. Electrical demand varies both on a monthly and daily basis. Monthly purchases of electricity are available from DEIS-2.

Daily electrical demand profiles during the summer and winter for the top ten bases were documented by the Naval Weapons Center (Reference 23). For each base, the summer and winter demand profiles were averaged to yield one daily demand profile. Analogous to the process steam profile, electrical demand profiles reflect the daily work cycle. An example for Portsmouth, Virginia is given in Figure 5-3.

5.1.2 Energy Availability

Refuse available for use by RDF energy systems was restricted to combustible refuse generated by the respective Navy bases. This excludes refuse potentially available from nearby communities. For example, the Norfolk Naval Complex generates 120 tons/day of refuse. An additional 800 to 900 tons/day are available from the city of Norfolk, but this source was not considered. Refuse available at each of the top ten energy consumers is given in Table 5-3 (Reference 27). We assumed that RDF could be used for the combined requirements of heating, process steam, and electricity.

Coal supplies three types of combustion systems: fluidized bed combustion, conventional (grate) combustion, and coal-fired cogeneration. FBC and conventional coal combustion compete separately in the heating, process steam, and electricity energy sectors, whereas cogeneration simultaneously delivers process steam and electricity. For simplicity, we assumed that an unlimited supply of coal is available at each base. Realistically, the capacity of rail, truck, and barge transportation networks constrain coal supply. However, coal use may be restricted in areas which violate current federal air quality standards (nonattainment

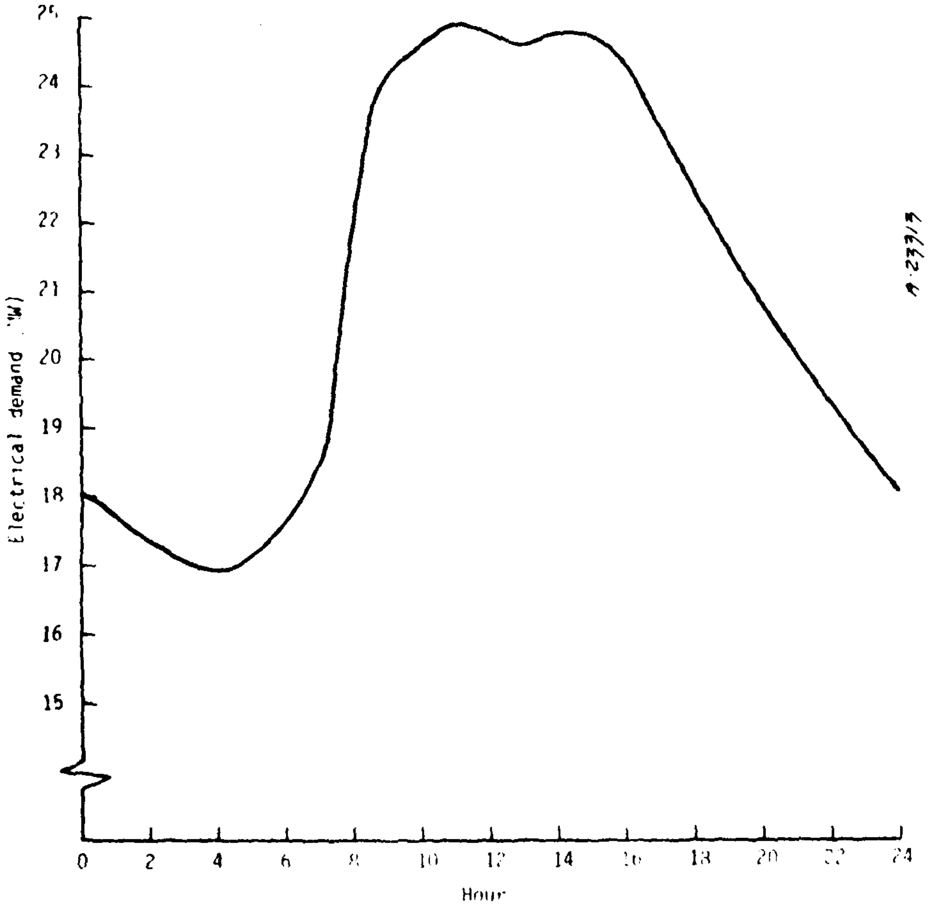

Figure 5-3. Daily electrical demand profile for Portsmouth, Virginia.

TABLE 5-3. ENERGY AVAILABILITY FOR THE TOP TEN ENERGY CONSUMERS

Site	Refuse (tons/day)	Air Quality Attainment Status (yes/no)	Daily Average Insolation Flat Surface (Btu/ft^2)	Average Wind Velocity (mph)	Geothermal Potential	Land Area (10^6ft^2)
Norfolk, VA	120	Yes	1339[a]	8.71	None	13.89
San Diego, CA	190	No (NO_x, particulates)	1338	5.74	None	6.53
Philadelphia, PA	50	Yes	1339[a]	9.33	None	1.84
Charleston, SC	70[b]	No (NO_x, particulates)	1516	8.14	None	22.18
Pearl Harbor, HI	70[b]	Yes	1778	11.12	None	Unlimited
Great Lakes, IL	41	Yes	1329	9.33	None	2.68
Portsmouth, VA	54	Yes	1339[a]	8.71	None	6.53
Pensacola, FL	190	Yes	1678	9.02	None	19.57
Bremerton, WA	68	Yes	1117	9.44	None	8.70
New London, CT	30[b]	No (particulates)	1243	9.25	None	2.70

[a]Based on insolation in Sterling, Virginia
[b]Estimate

areas). For this study, we further stipulated that a Navy base cannot employ coal combustion systems unless the air quality control region (AQCR) in which the base is located meets proposed federal standards. In addition, all coal combustion systems were modeled (performance and cost) to include pollution control equipment capable of meeting proposed federal stationary source standards for boilers larger than 250 MBtu/hr* (see Table 5-4). Flue gas desulfurization (FGD), electrostatic precipitators (ESP), and staged combustion (SC) were selected to control SO_x, particulates and NO_x emissions, respectively.

TABLE 5-4. PROPOSED FEDERAL STATIONARY SOURCE STANDARDS (Reference 28)

Pollutant	Proposed Standard
SO_x	1.2 lbm/10^6 Btu coal burned
Particulates	0.03 lbm/10^6 Btu
NO_x	0.50 lbm/10^6 Btu -- Subbituminous coal 0.60 lbm/10^6 Btu -- Bituminous coal

Among the top ten energy consumers, San Diego, Charleston, and New London do not currently meet proposed federal air quality standards (see Table 5-3) and therefore with our assumptions cannot utilize coal combustion systems (Reference 29).

---

*Although most Navy boilers are smaller than 250 MBtu/hr, it was assumed as a worst case that the same standards would apply to the smaller boiler sizes.

Insolation and wind data were extracted from magnetic tapes compiled at CEL and made available to us. These data were preprocessed into a form compatible with the NES optimization program. Techniques for reducing the data were described earlier in Section 4.2. Table 5-3 lists average insolation and wind velocity for the top ten consumers.

Geothermal energy was considered a viable alternate energy source for the process steam and electric demand sectors. Due to the extremely site specific nature of low temperature geothermal sources (e.g., shallow wells) and subsequent lack of a general energy model, low-grade geothermal energy was not considered a competitor in the heating demand sector. At all the top ten energy consumers except Pearl Harbor, potential geothermal reservoirs were either nonexistent or located too far from the base. Pertinent geothermal data are tabulated in Table 5-5. Although a geothermal reservoir lies within 15 miles of Pearl Harbor, unfortunately the site is not owned by the Navy and therefore was not considered.

The amount of land available for siting solar and wind systems is limited. Only stable land with no vertical restrictions was considered. Marshland, for example, was excluded. Reference 23 identified available land at the top ten consumers. This information is summarized in Table 5-3.

Finally, no constraints were placed on the purchase of electricity or fuel oil ($L_{MAX} = \infty$, refer to Section 2.2). We let the code select the optimum purchases of these conventional energy sources.

5.1.3 Energy Costs

Economic analysis of all energy sources assumes a system life of 25 years with the optimum solution implemented in 1985. All capital and fuel costs were escalated to this base year and are reported in real 1977

TABLE 5-5. GEOTHERMAL DATA FOR THE TOP TEN ENERGY CONSUMERS[a]

Navy Activity	Geothermal Site	Proximity (miles)	Subsurface Temp (^{o}C)	Thermal Potential (10^6 Btu)
Norfolk, VA	None	--	--	--
San Diego, CA	Salton Sea Heber	95 95	340 190	83.33×10^9 43.65×10^9
Philadelphia, PA	None	--	--	--
Charleston, SC	None	--	--	--
Pearl Harbor, HI	Lualualei	15	150	1.19×10^9
Great Lakes, IL	None	--	--	--
Portsmouth, VA	None	--	--	--
Pensacola, FL	North Gulf	150 to 675	No specific information. Very little potential.	
Bremerton, WA	Mt. Baker Mt. Ranier Glacier Park	90 65 120	165 170 165	0.794×10^9 0.794×10^9 0.794×10^9
New London, CT	None	--	--	--

[a]Reference 30.

dollars. Capital costs are discounted at 10 percent over the system lifetime, whereas fuel costs are inflated at differential rates recommended by NAVFAC. The differential inflation rates currently used in the code are itemized in Table 2-2 and are repeated here for convenience in Table 5-6.

TABLE 5-6. ENERGY ESCALATION RATES

Fuel	% Differential Inflation Rate
Coal	5
Fuel oil	8
Natural gas and LPG	8
Electricity:	
New England states	7
Pacific coast	7
All other states	6

Conventional energy costs for heating (space and hot water) as well as process steam were based upon decentralized boilers fired with low sulfur, No. 6 fuel oil. Fuel costs were differentiated according to three geographical regions: northeast, midwest-southeast, and west. For these regions, 1985 costs were \$2.89, \$2.97, and \$2.87/10^6 Btu, respectively. Fuel oil costs assigned to each Navy base are listed in Table 5-7.

For electricity costs we used actual electric prices charged by utility companies in 1977 to the various Navy bases. Electric costs are compiled in Reference 31. As recommended by NAVFAC, 1977 prices were inflated at 6 or 7 percent (depending upon the location) to yield 1985 electricity costs as given in Table 5-7. For the top ten energy consumers, electric costs vary widely from \$25/MWh at Bremerton, Washington to \$64/MWh at Portsmouth, Virginia.

TABLE 5-7. ENERGY COSTS[a] FOR THE TOP TEN ENERGY CONSUMERS

Site	No. 6 Fuel Oil Ref. 32	Electricity Ref. 31	Coal Ref. 32, 33, 34, 35	
	Cost ($\$/10^6$ Btu)	Cost (\$/MWh)	Cost ($\$/10^6$ Btu)	Sulfur Content (Low/High)
Norfolk, VA	2.89	43.51	1.58	High
San Diego, CA	2.87	63.23	1.60	Low
Philadelphia, PA	2.89	52.28	1.58	High
Charleston, SC	2.97	43.83	1.58	High
Pearl Harbor, HI[b]	4.40	55.67	--	--
Great Lakes, IL	2.97	40.32	1.33	High
Portsmouth, VA	2.89	63.91	1.58	High
Pensacola, FL	2.89	44.95	1.60	Low
Bremerton, WA	2.89	24.57	1.60	Low
New London, CT	2.89	52.58	1.58	High

[a]All costs are for 1985 expressed in real 1977 dollars.
[b]For Pearl Harbor, the cost for No. 6 fuel oil taken from Reference 36. It is assumed that coal cannot be economically delivered to Hawaii.

Analogous to fuel oil cost, coal costs were differentiated according to northeast, midwest-southeast, and western regions. Delivered 1985 costs assuming rail transportation in the contiguous U.S. are \$1.58, \$1.33, and \$1.60/10^6 Btu, respectively. Cost data were taken primarily from Reference 32 and verified using information from References 33, 34, and 35. Coal costs for the top ten energy consumers are also listed in Table 5-7.

All other costs such as capital equipment costs or operating and maintenance costs were computed with the algorithms currently in the code. See Appendix A for additional details.

5.2 RESULTS OF THE TOP TEN ENERGY CONSUMERS

5.2.1 Overview

Energy modelers typically compare only a single alternate energy source to existing conventional energy sources. Their approach often fails to identify the full economic potential of implementing a mix of alternate systems. However, the NES optimization program, developed in this study, not only compares energy costs of a set of alternate systems, but determines the optimum mix of both conventional and alternate energy systems.

As discussed previously, energy demand at each base was disaggregated into three energy-use categories: heating, process steam, and electricity. Various energy systems associated with each category compete on an economic basis (\$/10^6 Btu) to meet total energy demand. Cogeneration models allow single systems to compete across energy-use sectors. Energy demand varies both daily and annually. The NES optimization code matches energy supplied by a mix of alternative and conventional energy sources to the energy demand at a particular base.

Matching supply and demand is particularly critical in determining the economic viability of photovoltaic and wind systems whose output depends entirely on daily and annual variations in insolation and wind velocity. The optimum mix of systems satisfies total energy demand at minimum cost within the constraints on land area available for plant siting and constraints on fuel available for use by various generic groups of alternate energy systems (i.e., coal for coal conversion processes and refuse for RDF facilities).

The NES code assumes that the entire optimum mix of energy systems will be implemented simultaneously in the year 1985. This would require substantial, if not unattainable, funding during 1985. Realistically, systems would be commissioned in sequence of cost effectiveness at rates compatible with Navy investment schedules. Furthermore, gradual deployment of alternate energy systems would enable financial returns from systems built initially to be used as funding for subsequent systems. In addition, potential reductions in capital cost and improvements in performance due to innovation may encourage delaying implementation of certain systems to a later year. For example, a breakthrough in silica technology would substantially reduce costs of photovoltaic cells. The primary objective of this study was to identify cost-effective alternate energy sources, regardless of investment criteria. The NES code not only identifies potential systems, but also provides comparative energy cost data upon which investment decisions can be made.

The following subsections describe the impact of various alternate energy systems at the Navy's top ten energy consumers. In this discussion, emphasis was placed on overall trends indicated by aggregating the results of all ten bases. The actual mix of systems for

each base as determined by the NES code is tabulated and further discussed in Appendix B.

5.2.2 Evaluation of Alternate Energy Systems

Refuse Derived Fuel

Although RDF is a relatively inexpensive method of producing heat and low pressure process steam, it is not capable of producing high pressure steam required for process steam applications and electrical generation at efficiencies competitive with coal combustion systems. Fuel to electricity efficiency of RDF is 23 percent, whereas efficiency for coal combustion systems is 36 percent. Consequently, RDF is cost effective primarily in the heating and process steam sectors, but not the electric sector. Also, because RDF systems have no economies of scale,* they are more cost competitive relative to coal systems at small demands. This is clearly illustrated in Figure 5-4 which compares energy costs in the heating sector for FBC, conventional coal, and RDF systems. Energy costs of coal combustion systems rise rapidly at small system sizes due to economies of scale, whereas RDF costs are constant with size at $\$4.08/10^6$ Btu. Thus, for east and west coal regions (coal cost equals $\$1.58$ and $\$1.60/10^6$ Btu, respectively), RDF is cost effective at system sizes less than 1.1×10^{12} Btu/year.

A similar analysis holds true for the steam sector. As illustrated in Figure 5-5 for eastern and western coal, RDF is cost effective at system sizes below 1.0×10^{12} Btu/year.

*This may change in the future as more systems are built (see Appendix A).

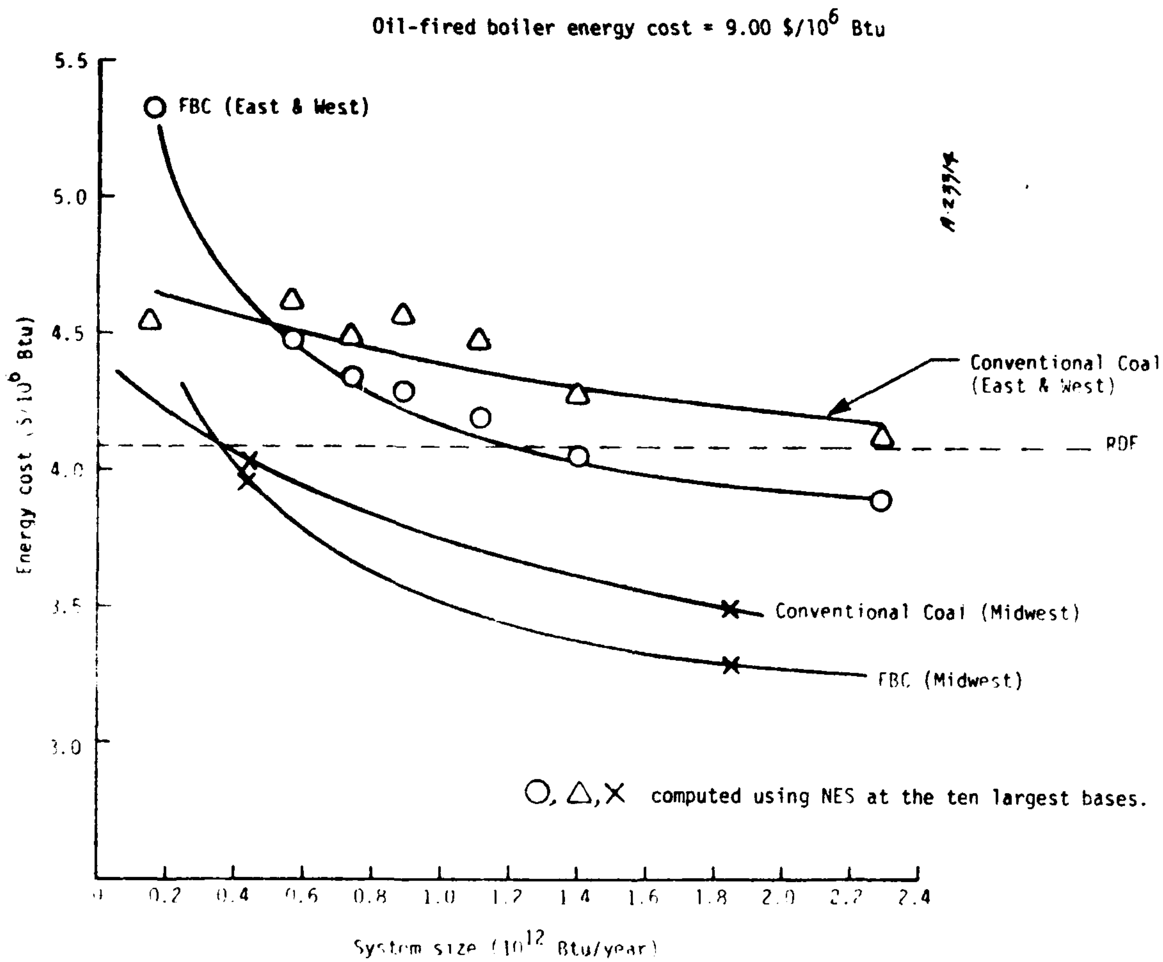

Figure 5-4. Energy cost comparison: heating demand sector.

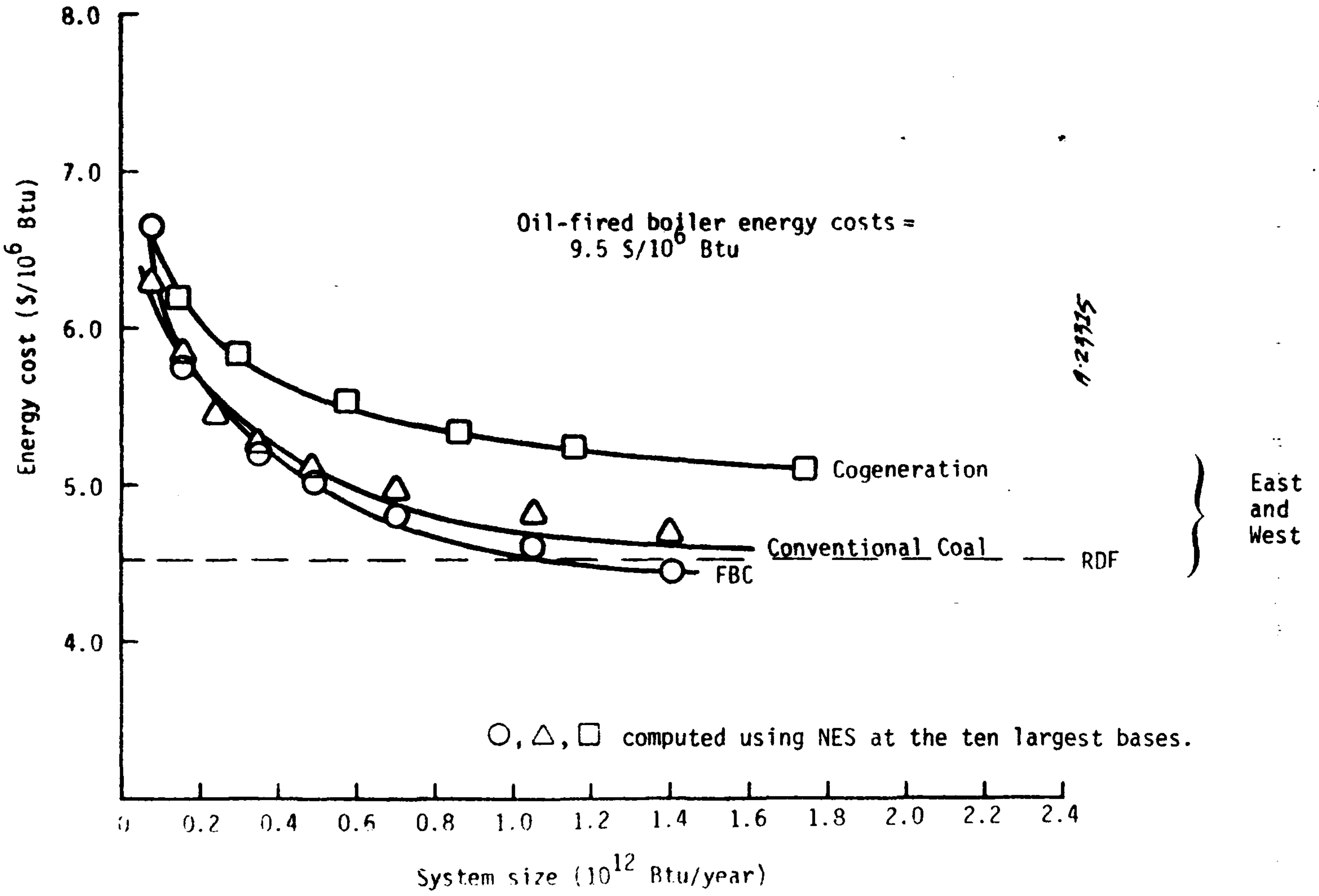

Figure 5-5. Energy cost comparison: process steam demand sector.

AD-A081 383 ACRUEX CORP MOUNTAIN VIEW CA ENERGY AND ENVIRONMENTAL DIV F/G 10/3
APPLICATION POTENTIAL OF ENERGY SYSTEMS AT NAVY SITES. VOLUME I--ETC(U)
JAN 80 S J ANDERSON, M D JACKSON, S J CHAMP N68305-78-C-0009

UNCLASSIFIED CEL-CR-80.006-VOL-1 NL

2 OF 3

AD A081383

Finally, although RDF is cost competitive at smaller sizes, its actual penetration into an energy sector is limited by constraints on available refuse at the various Navy bases (see Table 5-3). Therefore, in some cases, it may be economical to import refuse from local communities to support larger RDF facilities.

Fluidized Bed Combustion (FBC) and Cogeneration

Fluidized bed combustion was modeled to compete in all three energy use sectors. For the Navy's top ten energy consumers, FBC dominates larger demands in the heating, process steam and electricity energy sectors. As discussed above, RDF is FBC's primary competitor in the heating sector. However, in the process steam and electricity sector, FBC competes with a cogeneration system that simultaneously delivers both process steam and electricity. Although conventional coal competes in the electricity and steam sectors, and wind and photovoltaic systems compete in the electricity sector, all produce more expensive energy than either FBC or cogeneration systems.

For this study, the cogeneration steam topping cycle was modeled to deliver a fixed ratio of steam to electricity -- specifically, 6.5 Btu steam per 1 Btu electricity. For the top ten energy consumers, process steam demand was approximately equivalent to electrical demand (see Table 5-2). Consequently, the size of the cogeneration system is constrained by the magnitude of the steam demand and it typically supplies only a fraction of the electrical demand. Electrical demand not satisfied by cogeneration is met by FBC and commercial purchases of electricity. Practically, a cogeneration system should be designed to accommodate substantial portions of both demands.

As discussed earlier, the NES optimization code minimizes total energy cost. Therefore, to meet the combined requirements for process steam and electricity, two separate FBC systems (electricity and steam) compete with a combination of cogeneration and FBC-electric systems. The most cost-effective combination of systems depends on a number of parameters:

- Absolute size of the steam and electrical demands -- both cogeneration and FBC have economies of scale; therefore, energy cost delivered by each system depends on system size
- Relative magnitude of each demand -- for the cogeneration-FBC electric combination, FBC is sized to meet the electrical demand not supplied by cogeneration. Thus, a high steam to electricity demand ratio requires only a small FBC-electric system which substantially increases energy cost.
- Cost of conventional energy -- each alternate energy system reduces cost for energy by reducing the use of expensive oil-fired boilers and purchases of commercial electricity. The net savings depends on the difference between alternate energy cost ($\$/10^6$ Btu) and conventional energy cost ($\$/10^6$ Btu) within each energy use sector. Restated, for a given cost of alternate energy, greater savings occur at higher conventional energy cost. The optimum (least cost) mix of systems then depends on the energy cost of oil-fired boilers and commercial electricity at each particular location.

The optimum combination of FBC/cogeneration systems depends on a number of interrelated variables. Computer analysis is required to identify the minimum cost solution. Results of the NES code reveal that

cogeneration and FBC-electric systems are most cost-effective for sites with a steam demand approximately equal in size to the electrical demand. However, for steam to electrical demand ratios greater than 2.0, two separate FBC systems are more cost effective. This is because of the larger economies of scale for FBC systems in the combined steam-electric sectors as compared to cogeneration systems.

Conventional Coal Combustion

At the magnitude of demand of the top ten energy consumers, energy from conventional coal combustion systems was more expensive than energy produced by both RDF and FBC systems. This is shown in Figures 5-4 and 5-5. Consequently, conventional coal combustion does not penetrate any of the three energy use sectors even through it is only $\$1.0/10^6$ Btu more expensive than FBC.

Solar

Performance of the photovoltaic system depends upon the insolation at a particular site. Energy cost varied from $\$50/10^6$ Btu at Pearl Harbor, Hawaii to $\$105/10^6$ Btu at Bremerton, Washington. These costs are well above the general price of \$25 to $\$30/10^6$ Btu charged for utility electricity.

Solar thermal systems produce energy to meet heating demand. Again, energy cost varies depending upon insolation, and ranged from \$11 to $\$20/10^6$ Btu at Pearl Harbor and Bremerton, respectively. Except for Pearl Harbor, solar thermal energy was higher than the typical price of $\$10/10^6$ Btu for heat produced by oil-fired boilers. At Pearl Harbor, through, the solar thermal system proved cost effective, delivering 0.06×10^{12} Btu/year.

Wind

Three sizes of wind energy systems were modeled in this study: 5 kW, 200 kW, and 1500 kW. Because performance of wind systems is a function of the cube of velocity, cost of wind generated electricity varies widely depending upon the wind velocity at each location. For the top ten energy consumers, wind energy cost ranged from a high of $\$1150/10^6$ Btu at San Diego to a low of $\$28/10^6$ Btu at Pearl Harbor. Electricity costs were generally between \$25 to $\$75/10^6$ Btu higher than utility produced electricity except at Pearl Harbor where a 1500 kW wind system economically delivered 0.29×10^{12} Btu/year of electricity.

Geothermal

As indicated in Table 5-5, none of the top ten energy consumers were within close proximity of potential geothermal reservoirs. Consequently, geothermal energy was not considered.

5.2.3 Summary

Table 5-8 presents a summary of the results for the top ten energy consumers. The results are for systems which would be implemented in 1985 and have a 25-year economic life. All costs are reported in 1977 dollars and include effects of inflation on fuel prices as well as equipment and maintenance costs. Further, all costs are levelized according to the procedures outlined in Section 2.2.3.

In the aggregate, these results indicate that the Navy could realize a savings of \$97.5 million per year by investing an additional \$246 million in alternate energy systems. This results in slightly more than a 2-year payback. The savings are achieved by displacing 2.5×10^6 barrels of oil per year and instead using 460 tons/day of refuse and 3250

TABLE 5-8. SUMMARY OF RESULTS: TOP TEN ENERGY CONSUMERS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Average Energy Cost ($/$10^6$ Btu)	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)
Heating	RDF	126.6	1.10	4.08	2.33	0.56	--
	FBC	4997.0	43.29	3.88	51.22	29.56	--
	Solar Thermal	61.4	0.53	10.99	5.25	0.69	--
	Oil-fired boilers	6358.0	55.08	9.13	32.76	58.07	1419.0
	Oil-fired boilers alone	11543.0	100.0	8.76	44.12	101.17	2577.0
Steam	RDF	111.0	1.07	4.53	2.07	0.50	--
	FBC	2604.0	25.14	3.98	24.15	12.11	--
	Cogeneration	2733.0	26.39	5.40	46.03	19.96	--
	Oil-fired boilers	4910.0	47.40	9.79	21.03	48.08	1201.4
	Oil-fired boilers alone	10358.0	100.0	9.51	33.13	98.49	2551.0
Electricity	RDF	240.9	2.63	10.60	11.79	2.55	--
	FBC	3866.0	42.27	9.54	81.91	44.42	--
	Cogeneration	558.6	6.11	5.40	--	--	--
	1500 kW Wind	293.4	3.21	27.88	45.00	8.33	--
	Commercial	4187.0	45.78	30.92	--	129.44	--
	Commercial alone	9146.0	100.0	27.57	--	252.15	--
Total Optimum Mix		31047	100.0		323.5	354.27	2621.0
Total Commercial/Oil Alone		31047	100.0		77.25	451.81	5128.0

Savings = $97.54 x 10^6/yr
Oil saved = 2,507,000 barrels/yr

tons/day of coal.* Reducing the amounts of oil consumed and commercial electricity purchased results in 50 percent self-sufficiency.

The largest cost savings is obtained by investing in on-base electrical generation equipment. Out of the 97.5 million, $67 million is saved by displacing commercial purchases of electricity.

This surprising result is a consequence of the large cost difference between alternate systems and commercial purchases. This difference is affected by the differential inflation rates for electricity and especially for coal. Two other contributions are cogeneration (which is "free" in this sector) and the relatively flat characteristics of the demand sector.

Most of the commercial purchases of electricity are at the four bases which, due to nonattainment, are excluded from burning coal. Electrical requirements at these bases nearly total all the commercial purchases shown in Table 5-8. The remaining mix of selected systems (RDF, FBC, wind and cogeneration) meet the demand without relying on expensive commercial purchases.

The second largest savings are achieved in the steam sector -- approximately $18 million per year. Most of these savings are realized by converting from oil-fired boilers to coal (FBC and cogeneration). RDF systems also contribute a small amount. As indicated in Table 5-8, most of the savings are due to differences in fuel costs.

*For these analyses, we assumed that oil-fired systems are the only systems currently used by the Navy. Costs of natural-gas-fired (or other) systems would be approximately the same as oil-fired systems.

The least savings are obtained in the heating sector -- $12 million/year. The primary difference between this sector and steam is the requirement for considerably larger "peaking" capacity. The results indicate that this sector is not as flat as either steam or electricity and the cheapest mix is obtained by adding oil-fired boilers instead of larger size coal-fired units.

Nonattainment significantly affects the potential savings for the top ten consumers. Three bases fall into our definition of nonattainment: New London, San Diego and Charleston. Pearl Harbor is also excluded from using coal because of prohibitive transportation costs. RDF is, therefore, the only viable system (solar and wind are economical at Pearl Harbor) and most of the demand for these bases is satisfied by either oil-fired systems or commercially supplied electricity. In the heating sector, 6358 x 10^9 Btu/yr is supplied by oil-fired boilers. Slightly less than half of this (2900 x 10^9 Btu/hr) is a result of nonattainment. In the steam and electrical sectors the effect is even greater: 4060 compared to 4910 x 10^9 Btu/hr for steam and 3900 compared to 4187 x 10^4 Btu/hr for electricity.

Some indication of the importance of converting to less expensive fuels is also shown in Table 5-8. By 1985 the Navy will be paying nearly $480 million per year just to operate and maintain 10 bases. This number, of course, depends strongly on the assumed escalation rates. Nevertheless, all attempts should be made to reduce these costs, either by reducing the demand (conservation) or converting to cheaper sources of energy.

Although the results show impressive savings, there are many uncertainties in the analysis which require future investigation. For

example, assumed values of differential inflation rates greatly affect the overall mix of systems and ultimately the potential savings. Other factors are the energy sectors (accuracy of data and effect of dividing into three sectors), site data, and system costings. The sensitivity of solutions to these variables should be determined.

It should be emphasized that aggregate results such as those presented here provide an overall picture, but do not provide enough information. A lot of the systems are very close in cost and the results of the methodology are therefore best used on a case-by-case basis. Fortunately, the code and methodology were built around this premise.

SECTION 6

NAVY-WIDE IMPACT OF ALTERNATE ENERGY SYSTEMS

The Navy's top ten energy consumers can markedly reduce energy costs by a mix of alternate and conventional energy sources. However, this requires substantial capital investment in RDF, FBC, and cogeneration energy systems. Investment in alternate energy systems at the Navy's remaining 115 bases can also further reduce total energy costs.

The NES computer code was used to determine the optimum mix of energy systems at the Navy's top ten energy consumers. This code could also be used to evaluate each of the other 115 bases, but this approach has two distinct disadvantages. First, it requires massive assembly of site specific data such as hourly insolation and wind velocity, monthly fuel consumption, annual refuse generation, and resident/nonresident population -- a time consuming and expensive task. Second, adequate data were not readily available for this study.

An alternative approach is to perform an optimization analysis for a selected set of Navy facilities which are representative of the entire Navy shore establishment. Analysis of the top ten energy consumers (see Section 5) revealed that the mix of energy systems at each base depends primarily on the magnitude of the energy use sectors, and, to a lesser extent, on site specific information such as weather and demand variations. This occurs for three reasons: (1) energy cost for

competitive systems (FBC, RDF, and cogeneration) varies strongly with size due to economies of scale, (2) energy cost for wind and solar systems which depends on site specific weather data was typically twice that of coal or refuse systems and, therefore, was never cost competitive (except at Pearl Harbor), and (3) daily demand variations were assumed the same for all bases. Consequently, the results of the top ten energy consumers can be applied to other bases of similar size without serious loss of accuracy.

The mix of energy systems for smaller bases (less than the top ten) can be estimated by extrapolating results from a select sample of smaller bases. Kingsville, Texas; Glenview, Illinois; Atlanta, Georgia; and Fort Lauderdale, Florida were selected as the sample bases for the smaller energy consumers. The selection criteria and the results of the NES code for these bases are discussed in Section 6.1. In Section 6.2, these results are extended to all small Navy bases and then incorporated with results from the top ten energy consumers to yield a complete survey.

6.1 RESULTS FOR THE SAMPLE BASES

A set of sample bases which represents all small Navy bases must provide information concerning market penetration (percent demand met by alternate energy systems), delivered energy cost, and capital investment requirements. A comprehensive approach would require analysis of a number of bases distributed evenly over the entire range of fuel consumption; specifically, 3.4 to 0.01 x 10^{12} Btu/year. This was beyond the scope of the present study. Instead, we chose to investigate a small sample of bases with demands less than 1.0 x 10^{12} Btu/year. These results were then used to extrapolate the mix of alternate energy systems for the range of smaller bases.

Potential sample bases with demands less than 1.0×10^{12} Btu/year were screened based upon the availability of weather and fuel consumption data. Table 6-1 lists the selected set of Navy bases. The remainder of this section describes the site data and results of the NES optimization code for these bases.

6.1.1 Site Data

Alternate energy systems compete with conventional energy systems within three energy-use sectors (heating, process steam, electricity) to meet total energy demand at minimum cost. The optimum mix of systems is determined by the NES computer code. Input required by the computer program includes energy demand, weather, and cost data. These are discussed below.

Energy Demand

The method for converting fuel consumption into disaggregate energy demand was discussed previously in Section 4.1, and reviewed in Section 5.1 for the top ten energy consumers. An analogous procedure was followed for the sample bases. DEIS-2 (Reference 16) lists fuel consumption at each base, while UCAR (Reference 17) identifies the fraction of process steam used to produce electricity. None of the sample bases generate their own electricity. During the day, heating demand is constant whereas both process steam and electricity vary. The diurnal process steam profile used for the top ten consumers was again employed for the sample bases.* Diurnal electrical demand profiles for the top ten consumers were tabulated in Reference 21. Unfortunately, the same profiles are not readily available for the sample bases. Therefore,

---

*These assumptions might be inaccurate for these smaller bases. Future investigations are needed to verify and/or develop better assumptions.

TABLE 6-1. ENERGY DEMAND FOR THE SAMPLE BASES

Site	Annual Energy Demand[a] (FY 1976)			
	Heating (10^9 Btu/yr)	Process Steam (10^9 Btu/yr)	Electricity (10^9 MWh/yr)	Total Demand (10^9 Btu/yr)
Naval Air Station at Kingsville, TX	26.98	50.45	28.9	176.1
Naval Air Station at Glenview, IL	152.7	85.06	8.11	265.5
Naval Air Station at Atlanta, GA	18.69	8.21	4.86	43.4
Naval Surface Weapons Center Detachment at Fort Lauderdale, FL	0.47	0.46	1.08	4.63

[a]Values for energy demand refer to delivered energy, calculated by reducing fuel consumption by conversion efficiency and distribution losses.

as an approximation, an electrical demand profile for the sample bases was generated by averaging the profiles at the top ten bases.* This profile is illustrated in Figure 6-1.

Energy Availability

Refuse available for RDF energy systems was restricted to combustible refuse generated by the respective Navy bases. The amount of available refuse was determined by contacting the public works department at each base. The results are given in Table 6-2.

Among the top ten energy consumers, we assumed an unlimited supply of coal was available for each sample base. However, we further stipulated that a base located in an area which violates current federal air quality standards cannot employ coal combustion systems. For sample bases, Glenview, Illinois does not meet air quality standards and, therefore, cannot use coal (Reference 35).

Table 6-2 also lists average insolation and wind velocity for the sample bases. Insolation and wind data were extracted from magnetic tapes and preprocessed using techniques described in Section 4.2.

No geothermal reservoirs are located at any of the sample bases. Therefore, geothermal energy was not considered an alternate energy source.

Land available for siting energy systems was determined by contacting each Navy activity directly. Only stable land with no vertical restrictions was considered (see Table 6-2).

---

*These assumptions might be inaccurate for these smaller bases. Future investigations are needed to verify and/or develop better assumptions.

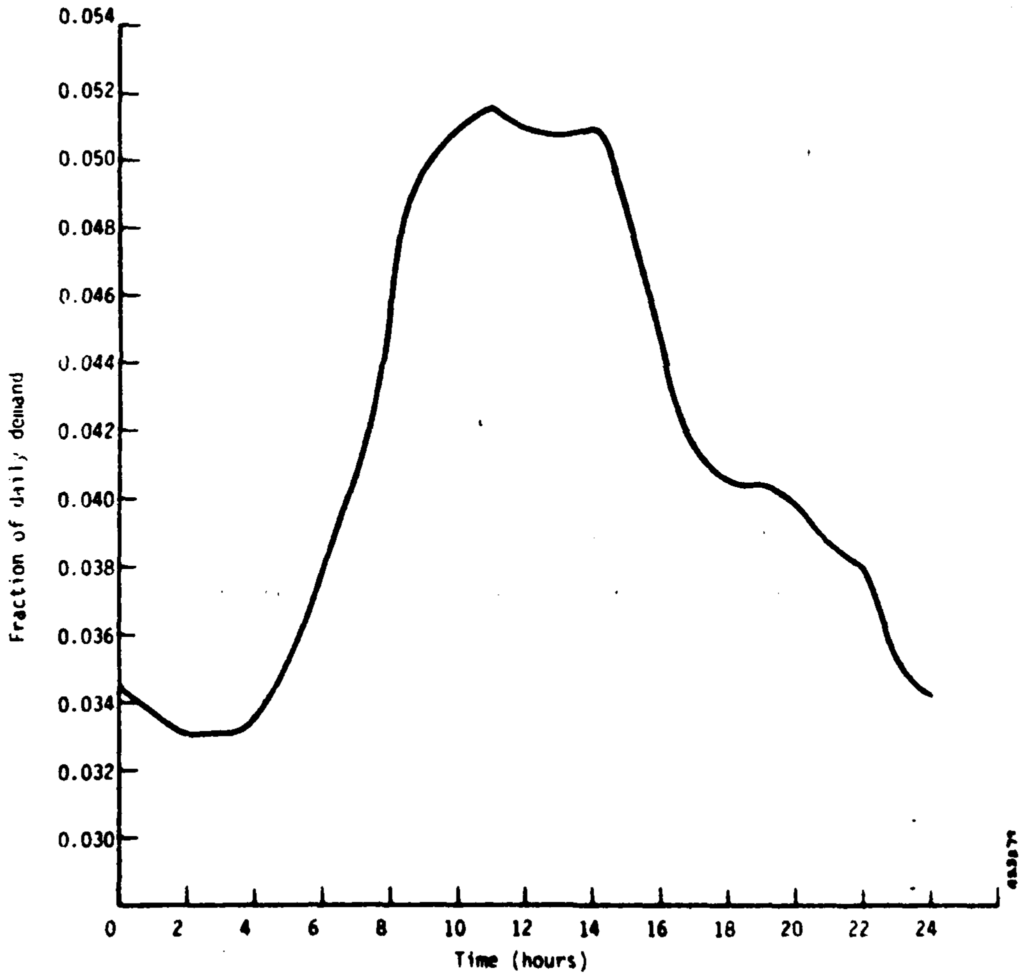

Figure 6-1. Average electrical demand profile.

TABLE 6-2. ENERGY AVAILABILITY FOR THE SAMPLE BASES

Site	Refuse (ton/day)	Coal Attainment Status (yes/no)	Daily Average Total Insolation Flat Surface (Btu/ft^2-day)	Average Wind Velocity (mph)	Geothermal Potential	Land Area (10^3 ft^2)
Kingsville, TX	8.0	Yes	1967	15.03	None	1,307
Glenview, IL	4.5	No (Particulates)	1330	9.33	None	174
Atlanta, GA	1.4	Yes	1297	6.55	None	218
Fort Lauderdale, FL	0.0	Yes	1672	8.79	None	44

Costs

Economic analysis of all energy systems assumes a system life of 25 years with capital cost discounted at 10 percent. All capital and fuel costs were escalated to 1985 and are reported in real 1977 dollars.

For the sample bases, 1985 costs for fuel oil and coal were \$2.97 and \$1.60/10^6 Btu, respectively. These costs were inflated at corresponding differential rates of 8 and 5 percent. For electricity costs we used actual electric prices charged by utility companies in 1977. These prices were inflated at 6 percent to yield 1985 electricity costs given in Table 6-3.

All other costs such as capital, operation and maintenance cost for the alternative energy systems are discussed in Appendix A.

6.1.2 Results

A detailed NES code evaluation for each sample base is tabulated in Appendix B. These data were summed to yield the totals presented in Table 6-4. Trends indicated by Table 6-4 are discussed below.

In the heating sector, RDF is capable of satisfying 7.5 percent of the demand with the remaining portion met by conventional oil-fired boilers. Coal combustion systems (FBC and conventional) did not supply any heat because at small sizes, their energy cost (\$6.5 to \$10/10^6 Btu) is much higher than that of RDF (\$4.08/10^6 Btu).

In the process steam sector, RDF, cogeneration, and oil-fired boilers met 5, 34, and 61 percent of the demand, respectively. Although RDF was not expected to supply process steam, at Glenview coal combustion was prohibited due to nonattainment, and it was more cost effective for RDF to supply steam rather than heat.

TABLE 6-3. ENERGY COST FOR THE SAMPLE BASES

Site	No. 6 Fuel Oil Ref. 32	Electricity Ref. 31	Coal Ref. 32, 33, 34, 35	
	Cost[a] ($\$/10^6$ Btu)	Cost[a] (\$/MWh)	Cost[a] ($\$/10^6$ Btu)	Sulfur Content (Low/High)
Kingsville, TX	2.97	48.77	1.60	High
Glenview, IL	2.97	34.27	1.60	High
Atlanta, GA	2.97	45.58	1.60	High
Fort Lauderdale, FL	2.97	52.92	1.60	High

[a]All costs are for 1985 expressed in real 1977 dollars.

TABLE 6-4. SUMMARY OF RESULTS: SAMPLE BASES

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Average Energy Cost ($/$10^6$ Btu)	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $/yr)	Equivalent Oil Consumption (10^3 barrels/yr)
Heating	RDF Oil-fired boilers	14.9 184.1	7.5 92.8	4.08 8.81	0.29 0.73	0.069 1.624	-- 41.12
	Oil-fired boilers alone	199.0	100.0	8.77	0.76	1.744	44.43
Steam	RDF Cogeneration Oil-fired boilers	7.18 49.80 87.20	5.0 34.5 60.5	4.53 6.30 9.67	0.14 1.52 0.34	0.033 0.430 0.847	-- -- 21.58
	Oil-fired boilers alone	144.18	100.0	9.59	0.46	1.383	35.54
Electricity	Conventional Coal Cogeneration Commercial	96.58 9.92 40.19	65.8 6.8 27.4	12.46 6.30 19.94	4.69 --[a] --	1.363 --[a] 0.802	-- --[a] --
	Commercial alone	146.69	100.0	23.66	--	3.470	--
Total Optimum Mix		489.9	100.0	--	7.71	5.168	62.70
Total Commercial/Oil Alone		489.9	100.0	--	1.22	6.597	79.97

Savings = 1.429 x 10^6 $/yr
Oil saved = 17,270 barrels/yr

[a]Cogeneration included in steam sector.

For small demand characteristics of the sample bases, conventional coal systems generate electricity at a cheaper price ($\$13/10^6$ Btu) than FBC systems ($\$15/10^6$ Btu). Therefore, conventional coal combustion rather than FBC together with cogeneration meet a substantial portion of the electrical demand (in contrast to the top ten consumers). Conventional combustion and cogeneration meet 66 and 7 percent of the demand, while the remaining portion is purchased from utility companies.

These results demonstrate the Navy can realize substantial energy cost savings by investing in alternate energy systems at smaller bases. For the sample analyzed, implementing alternate systems can realize a 4.5 year return on investment compared to approximately 2 years for top ten energy consumers. This difference can be attributed to economies of scale for these various systems -- the capital cost per energy produced for the top ten consumers is less when compared to the smaller bases.

6.2 SURVEY RESULTS

The ten largest Navy bases together account for 44 percent of the total energy demand throughout the shore establishment (limited to the Continental U.S., Hawaii, and Alaska). The NES computer code determined the optimum mix of alternate energy systems for these bases. The remaining 56 percent of the demand is used by 115 smaller bases. In this section, the sample results are extrapolated and combined with the top ten results giving the potential impact of alternate systems Navy-wide.

6.2.1 Mix of Energy Systems for Smaller Bases

The NES results shown in Table 6-4 were used to determine the mix of alternate energy systems for the smaller bases. As indicated by the results of Table 6-4, FBC systems are not cost effective at smaller demands. This is in contrast to the top ten consumers where FBC and

cogeneration dominated all three sectors (see Section 5). Other trends inferred by both the results summarized in Table 6-4 and those of the top ten energy consumers are:

- RDF meets a substantial portion of the heating demand, while the system size is limited by available refuse
- Of the alternatives, cogeneration dominates the process steam demand
- Cogeneration, conventional coal combustion, and commercial purchases combine to meet electrical demand
- Performance of solar and wind energy systems varies widely depending upon location. Thus, each base must be evaluated individually to determine the economic feasibility of solar and wind systems. In general, based on results from the top ten consumers, average daily insolation must be greater than 1800 Btu/ft^2, and average wind velocity must be in excess of 13 mph for solar and wind systems to be cost effective relative to conventional sources.
- High temperature geothermal reservoirs capable of supporting electrical or process steam exist at only two locations -- Adak, Alaska and China Lake, California. Since these are the only sources, we neglected high temperature geothermal as a possiole alternative. Further, low temperature sources (shallow-wells) were also neglected in the space heating sector because of the site-specific nature of this potential source.

6.2.2 Penetration of Alternate Systems for Smaller Bases

The preceding analysis identified RDF, cogeneration and conventional coal combustion systems as the most cost-effective alternatives to

oil-fired boilers or commercial purchases of electricity. Solar, wind and geothermal systems were neglected, even though these systems may be cost effective at some bases.*

To estimate the potential impact of RDF, cogeneration and conventional coal combustion, it is necessary to estimate the demand in each energy-use sector and to estimate the mix of systems in each sector. The energy demand was determined by using the aggregate results for the top ten. As shown in Table 5-8, the energy demand is split almost equally across all three sectors: 37 percent for heating, 33 percent for steam, and 29 percent for electricity. This distribution was also verified Navy-wide from the fuel consumption data presented in Reference 2.

The following assumptions were made regarding the mix of energy systems:

1. Heating Sector:
   - 10 percent RDF
   - 90 percent oil-fired boilers
2. Steam Sector:
   - 80 percent cogeneration
   - 20 percent oil-fired boilers
3. Electrical Sector:
   - 15 percent cogeneration
   - 75 percent conventional coal
   - 10 percent commercial purchases

*The overall impact of these systems is small based on the results of the top ten and four sample bases.

This mix was selected based on our interpretation of the NES results for the top ten and four sample bases. A key factor in interpreting these results was our assumption that coal could be used at all small bases.

Based on results of the sample bases, RDF meets approximately 10 percent of the heating demand. Here, we assumed RDF is limited only to the heating sector, and refuse availability limits its penetration. Actually, according to the NES results, RDF could probably penetrate all three sectors -- depending on site specific energy costs.

Again, based on the sample results, coal-fired cogeneration systems supply slightly more than 80 percent of the process steam requirements. This system is the most economical because it also meets some fraction of the electrical demands. However, this assumption might be too high for several reasons. First, smaller bases are generally not centralized in energy use, so the application of cogeneration systems might not be practical. Second, small bases might fall in nonattainment regions and would be excluded from burning coal. Overall, our assumption is probably high and, therefore, indicates the maximum potential input for the small bases.

In the electrical sector, we assumed that the demand could be met by a combination of cogeneration, conventional cell combustion, and commercial purchases. Again, the mix selected is based on the results for the sample bases assuming coal was not excluded. All the results obtained so far using the NES code show that due to the high costs of commercial electricity, large potential savings can be made by minimizing purchases of commercial electricity. Again, our assumptions probably represent the maximum potential impact.

6.2.3 Results

Given the mix of energy systems and their market penetration into each of the three energy sectors, the energy models described in Appendix A were used to calculate capital cost, fuel requirements (based upon system efficiency), and operation and maintenance cost of the various energy systems. Capital cost per unit of energy output varies with system size due to economies of scale. Thus, for the range of system sizes evaluated in the survey, capital costs were weighted according to demand.

For the survey, fuel oil, coal, and electricity prices were assumed to be \$2.97, \$1.60, and \$30.9/10^6 Btu, respectively. These correspond to typical midwest prices.

Uniform annual cost for each competitive system was calculated based upon the formulation described in Section 2.2.3. Uniform annual cost together with energy delivered by each energy source yields the comparative cost of energy for the survey bases. These results are given in Table 6-5. Implementing these systems requires an additional investment of \$505 million in alternate energy systems at smaller bases (smaller than the top ten). The results indicate the Navy can potentially save \$242 million per year and reduce oil consumption by 3.09 million barrels/year, but would require 2852 ton/day of coal and 868 ton/day of refuse.

As described earlier, solar and wind systems are cost effective at only a few locations. The survey approach adopted by this study failed to determine the actual penetration of these alternatives. However, Navy activities that could potentially support economic wind systems include San Bruno, Pearl Harbor, China Lake, Boston, Nantucket, and Corpus Christi. Navy activities that could potentially support economic solar

TABLE 6-5. SUMMARY OF RESULTS: SMALL BASES NAVY-WIDE

Energy Use	Model	Delivered Energy (10^{12} Btu/yr)	Fraction of Demand Met (%)	Average Energy Cost ($\$/10^6$ Btu)	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$/yr)	Equivalent Oil Consumption (10^3 barrels/yr)
Heating	RDF Oil-fired boilers	1.54 13.86	10.0 90.0	4.08 8.74	26.0 51.98	6.28 121.12	-- 3094
	Oil-fired boilers alone	15.4	100.0	8.74	57.75	134.53	3437
Steam	Cogeneration Oil-fired boilers	11.09 2.77	80.0 20.0	6.04 9.51	197.9 8.17	77.35 26.35	-- 687
	Oil-fired boilers alone	13.86	100.0	9.51	40.83	131.75	3437
Electricity	Cogeneration Conventional Coal Commercial	1.70 8.69 1.16	15.0 75.0 10.0	6.04 13.15 30.90	--[a] 319.5 --	--[a] 113.94 35.84	-- -- --
	Commercial alone	11.55	100.0	30.90	--	356.90	--
Total Optimum Mix		40.81	100.0	--	603.55	380.88	3781
Total Commercial/Oil Alone		40.81	100.0	--	98.58	623.18	6874

Savings = 242 x 10^6 \$/yr
Oil saved = 3.09 x 10^6 barrels/yr

[a]Cogeneration included in steam sector.

systems include Pearl Harbor, Barbers Point, and Honolulu in Hawaii; and El Centro and China Lake in California. A detailed analysis of these bases by the NES optimization code is recommended.

Similarly, the potential for geothermal energy should be assessed at Adak, Alaska and China Lake, California.

6.2.4 Summary

The survey bases and the top ten energy consumers together constitute a complete evaluation of alternate energy systems for the entire Navy shore establishment. The combination of the top ten results and the results given in Table 6-5 indicate that the Navy as a whole can save $340 million per year by investing an additional $751 million, yielding an average 2.2-year return on investment. The aggregate of these systems would consume 1328 ton/day of refuse and 6102 ton/day of coal, but would reduce oil consumption by 5.6 million barrels per year. This result assumes that all alternate systems are implemented simultaneously in 1985. Realistically, various energy systems would be gradually phased in over several years.

SECTION 7

CONCLUSIONS AND RECOMMENDATIONS

In developing the NES optimization code, emphasis was placed in three primary areas: (1) site-specific data, (2) technical and cost data for alternate systems and (3) a procedure for simulating the decisionmaking process. We felt it was critical to select a methodology which would incorporate disaggregated energy demand data as well as other important site characteristics. In this manner, optimum mixes of alternate and conventional energy sources could be determined based on meeting the required demands and minimizing overall energy costs.

We considered two approaches: nonlinear programming and market penetration analysis. Both approaches deal with disaggregate end use data. Nonlinear programming tends to give discrete solutions, whereas a market penetration approach provides a distribution of possible solutions. A nonlinear optimization program determines the type and size of both alternative and conventional energy sources which meet energy-use requirements at minimum cost given site characteristics such as fuel costs, demand variations, and fuel availability. In contrast, market penetration analysis identifies cost distributions of technologies considering again specific site factors and then computes appropriate technologies in specific service sectors. The result is a distribution of viable (not necessarily optimal) alternatives competing within the service sector.

The nonlinear programming approach was selected in this study because it is quantitative and conceptually simpler than a market penetration analysis. Further, this approach also provides a tool in the form of a computer program capable of identifying criteria at the local level that determine the economic feasibility of alternate energy systems. For example, the NES optimization code can determine the viability of photovoltaic systems by matching daily electrical demand and insolation profiles; strictly a site specific phenomena.

A total of 17 alternate energy systems were conceptualized and incorporated in the NES code. These systems compete against conventional energy sources in heating, process steam and electrical demand sectors. Energy sources for these systems included wind, solar, coal, refuse derived fuels, and geothermal.

Two analyses were performed using the developed procedure: a detailed evaluation for the Navy's top ten energy consumers and a Navy-wide estimate of the impact of alternate systems. The Navy-wide estimate was completed in considerably less detail than the top ten results and indicates our best guess of potential savings by converting to alternate sources of energy.

With any optimization technique, assumptions are required to simplify the analysis. The assumptions and resulting limitations adopted in this study are:

- Total energy cost can be reduced by using cost-effective alternate energy systems (solar, FBC, etc.) or employing energy conservation measures. Although alternate energy systems were modeled, in this study conservation was not. Subsequent

analysis of Navy bases should evaluate the impact of conservation measures relative to alternate energy systems.

- Alternate energy systems were modeled as central powerplants that distribute heat, process steam, and electricity to various end-users. We further assumed that a distribution system with sufficient physical life exists at each base. Therefore, capital investment in a new distribution system was not required. Clearly, at bases without existing or sufficient distribution networks, either decentralized energy systems must be employed or cost for a distribution system must be included in the cost of a central powerplant. Neither of these options were included in the current code.
- In the heating and process steam sectors, alternate energy systems were compared against the costs of conventional oil-fired units. For comparison, we included total replacement costs (initial capital as well as recurring and nonrecurring costs). All potential savings reflect the cost differential between these replacement costs and respective alternate energy costs.
- In the electrical sector, costs of alternate systems were compared against actual commercial purchases for a given base. Actual electrical prices were appropriately inflated and discounted over the analysis time frame (1985 to 2010).
- The NES optimization program is a static rather than dynamic economic model. Thus, implementation of cost-effective alternative energy systems was assumed to occur simultaneously in 1985. Realistically, energy systems would be gradually

phased into operation over a period of time compatible with established Navy investment scenarios. In fact, potential reductions in capital cost and improvements in performance of energy systems due to innovation may encourage delaying implementation of certain systems to a later year. In addition, "behavioral lag" resulting from a reluctance to invest in new, innovative technologies may further postpone construction of energy systems, but this also was not considered.

7.1 CONCLUSIONS

One objective of this study was to estimate the impact of alternate systems for the entire Navy shore establishment. Two analyses were performed to estimate this impact: a detailed analysis of the Navy's top ten energy consumers and a detailed analysis of four smaller bases.

The top ten bases account for nearly 44 percent of the demand required by the Navy, whereas the remaining 115 activities require 56 percent of the demand. The smaller bases range in size from 3×10^{12} Btu/yr to 0.01×10^{12} Btu/yr. For the smaller activities, we selected four representative locations and used the NES code to predict the most cost-effective mix of alternate systems. These results were then combined and extrapolated based on the aggregate demand for the smaller bases.

An estimate of the potential impact for the shore establishment was determined by combining the top ten results and the extrapolated results for the smaller bases. Based on the assumptions for this analysis and our interpretation of the results, the combined results probably represent the maximum potential impact.

Conclusions are presented in terms of overall trends, top ten results, and combined Navy-wide results. The economic parameters for each analysis were unchanged. The time frame for analyses was 1985 to 2010 (25-year system life). The discount rate was 10 percent and differential inflation rates (applied to fuel only) were as recommended by the Navy.

7.1.1 Overall Trends

Coal systems were found to be the most cost effective in all three demand sectors. This result is not too surprising since the coal costs are considerably less than other conventional sources of energy. The methodology, however, quantifies the amount used and where coal-fired systems are most cost effective.

The largest cost savings are obtained in the electrical sector. In all solutions it was more cost effective to use alternate energy systems to generate on-base electricity instead of purchasing from local utilities. The optimization procedure is driven to this result because of the large price difference between coal systems (primarily fuel costs) and commercial electricity prices.

Displacing conventional oil-fired units in the heating or steam sectors is considerably less cost effective than displacing commercial purchases of electricity. The steam sector is slightly better than the heating sector because of cogeneration. The optimization procedure is driven to this result because of the relative differences in fuel costs; oil and coal being comparable in costs while electricity is considerably higher.

In all three sectors conventional sources (oil-fired or commercial electricity) supply some portion of the demand. Because of the variations in demand, it is more cost effective to use conventional sources as

peaking units. This essentially reduces the size, and therefore, the capital costs of the alternate systems competing in the demand sector.

In general, solar and wind energy systems are not economically feasible in the time frame considered (1985 to 2010). Based on results from the top ten energy consumers, average daily insolation must be greater than 1800 Btu/ft^2, and average annual wind velocity must be in excess of 13 mph for solar and wind systems to be cost effective relative to conventional sources.

7.1.2 Top Ten Results

Investing $246 million in alternate energy sources at the Navy's top ten energy consumers can realize a savings of approximately $97 million per year yielding a return on investment of 2.5 years. This would reduce oil consumption by 2.5 million barrels per year, but would consume 460 ton/day of refuse and 3250 ton/day of coal.

The optimum mix of alternate and conventional energy systems for the top ten energy consumers was:

- RDF, FBC, and oil-fired boilers satisfy space heating and hot water demand
- Cogeneration (coal-fired steam topping cycle), FBC, and commercial purchases meet electrical demand
- Cogeneration, FBC, and oil-fired boilers satisfy steam demand

7.1.3 Navy-Wide Results

Based on a sample survey and the top ten results, the total Navy shore establishment can save $340 million per year by investing $751 million in alternative energy systems yielding a 2.2-year return on investment. This would reduce oil consumption by 5.6 million barrels per year and would consume 1328 ton/day of refuse and 6100 ton/day of coal.

Therefore, self-sufficiency from foreign supplies of fuel oil is cost effective.

For small Navy bases (smaller than the top ten energy consumers), the optimum mix of alternate and conventional energy systems was:

- RDF and oil-fired boilers satisfy the space heating and hot water demand
- Cogeneration, conventional coal combustion, and oil-fired boilers satisfy process steam demand
- Cogeneration (coal-fired steam topping cycle) and commercial purchases meet the electrical demand

7.2 RECOMMENDATIONS

The results obtained during this study illustrate the large potential savings that can be achieved by converting to alternate energy systems. These savings reflect the impact of inflation on fuel prices and illustrate that the Navy will be paying considerably more for energy in the future.

The results quantify -- based on the economic assumptions -- a minimum cost approach. The aggregate results give overall trends regarding the mix of alternate systems. However, of the 17 systems modeled, many were not cost competitive. Further, those that were cost effective might not be optimum (cogeneration, for example). Future studies should examine variations of those systems which were cost effective.

The optimum mix of energy systems at each Navy base depends upon a number of site-specific factors including the magnitude of the energy demand, seasonal and daily demand variations, insolation and wind velocity, fuel cost (coal and electricity), differential fuel inflation

rates, and fuel availability (refuse and coal). The sensitivity of our results to changes in these parameters was not examined; particularly variations in fuel cost and fuel differential inflation rates which may significantly alter the final results. The sensitivity of the solution to these changes should be investigated. Similarly, sensitivity of the optimum solution to changes in specific energy system parameters such as efficiency, capital cost, and operation cost should be examined.

Because energy end-use data was not readily available, energy demand was disaggregated into three broadly defined energy-use sectors: space heating and hot water, process steam, and electricity. Further disaggregation into commercial, industrial, and residential end-use would better simulate actual energy use and thereby improve accuracy of the NES optimization code but would require substantial expansion of the existing UCAR and DEIS-2 energy demand data bases. This option should be considered.

The impact of alternate energy sources at the entire Navy shore establishment was estimated by combining the results from analyses of the ten largest energy consumers and the extrapolated results based on a sample of four small (energy demand less than 1.0 x 10^{12} Btu/yr) bases. These results should be confirmed by analyzing additional bases distributed in size between these extremes.

Performance and cost of alternate energy systems were based on best estimates available at the time of the study. As potential energy systems are commercialized and more accurate data are available, existing models should be updated accordingly, and the list of energy systems expanded.

REFERENCES

1. "U.S. Navy Energy Plan", U.S. Navy Energy Office (OP-4B) Washington, DC, January 1977.

2. Slaminski, J. M., "Energy Exploratory Development Program for the Naval Shore Establishment", Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA.

3. Devine, M., H. Kumin, and A. Aly, "Operations Research Problems in the Economic Design and Operation of Solar Energy Systems," presented at IGT Energy Modeling and Net Energy Analysis Symposium, August 1979.

4. Greenberg, H. J. and F. H. Murphy, "Modeling the National Energy Plan," presented at IGT Energy Modeling and Net Energy Analysis Symposium, August 1979.

5. Shugar, T. A., N. F. Shoemaker and M. L. Eaton, "Optimization Model for Integrated Alternate Energy Systems," TM51-78-03 Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA, November 1977.

6. Economic Analysis Handbook NAVFAC P-442, Department of the Navy, Naval Facilities Engineering Command, Alexandria, VA, June 1975.

7. "Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000," Vol. I, Primary Model Documentation, Energy and Environmental Analysis, Inc., Arlington, VA, April 1977.

8. Ciliano, R., M. H. Fallah, D. R. Limaye, "An Evaluation Model of Solar Industrial Process Heating," MATHTECH Inc., presented at IGT Energy Modeling and Net Energy Analysis Symposium, August 1979.

9. Cooper, C. and E. B. Stear, "Analysis of Algorithms Used in Civil Engineering Laboratory Report, 'Optimization for Integrated Alternate Energy Systems,'" Department of Electrical Engineering and Computer Science, University of California, Santa Barbara, CA, July 1978.

10. Smith, G. W., Engineering Economy; Analysis of Capital Expenditures, 2nd Edition, The Iowa State University Press, 1975.

11. Energy Escalation Rates for Short-Term Costing and Life Cycle Costing, NAVFACENGCOM ltr 1023B/JNW, 23 Aug 1976.

12. Fraas, A. P., "Application of the Fluidized Bed Coal Combustion System to the Production of Electric Power and Process Heat," Energy Divison Oak Ridge National Laboratory, AIChE Meeting, Kansas City, Missouri, April 1976.

13. "Conversion of Refuse to Energy," First International Conference and Technical Exhibition; Montreux-Switzerland, IEEE Catalog 75CH1008-2 CRE, November 1975.

14. "Decision-Makers' Guide in Solid Waste Management," Guide SW-500, Office of Solid Waste Management Programs; U.S. Environmental Protection Agency, pp. 155-158, 1976.

15. "The Development of the Basis for an Integrated Alternative Energy Plan for the Sewells Point Naval Complex, Norfolk, Virginia," Battelle's Columbus Laboratories, ERDA, Dep. Navy Atlantic Division, August 1977.

16. "Defense Energy Information System," arranged by host activity, Department of the Navy Western Division, San Bruno, California, 1977.

17. "Utilities Cost Analysis Report," available from host activity, NAVCOMPT FORM 2127 (Rev. 8-68).

18. "Alternative Strategies for Optimizing Energy Supply Distribution and Consumption Systems on Naval Bases, Vol. 1, Near-Term Strategies," CR 74.006, CEL, Port Hueneme, CA, November 1973.

19. Personal communication with Ray Bergman, Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA, December 1978.

20. "Utilities Target Manual," NAVFAC MO-303, Department of the Navy, Naval Facilities Engineering Command, Washington, D.C., May 1972.

21. "Guidelines for Saving Energy in Existing Buildings," Building Owners and Operators Manual ECM 1, Conservation Paper No. 20, Federal Energy Administration, Office of Energy Conservation and Environment, June 1975.

22. "Distribution of Manpower in U.S. by State," prepared by Navy Comptroller, 1977.

23. Lee, S. M., "Site Characteristics of the Navy's Ten Largest Energy Users," Advanced Tech. Div. Ordnance Systems Dept., Naval Weapons Center, China Lake, CA, NWC Tech. Memorandum 3487, April 1978.

24. Beckman, Klein, and Duffie, "Solar Heating Design by the f-Chart Method," Solar Energy Laboratory, Univ. of Wisconsin, Madison, WI, 1977.

25. Liu, B.Y.H., and R. C. Jordan, "The Interrelationship and Characteristic Distribution of Direct, Diffuse, and Total Solar Radiation."

26. Eaton, M. L. and T. A. Shugar, "A Statistical Sample of Navy Activities Representing Navy Energy Characteristics," TM 51-79-07, Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA, May 1979.

27. Personal communication with the Public Works Department at each Navy base.

28. Federal Register, Vol. 44, No. 113, June 11, 1979.

29. Federal Register, Vol. 43, No. 43, March 3, 1978.

30. "Assessment of Geothermal Resources of the United States," Geological Survey Circular No. 726, U.S. Department of the Interior, 1975.

31. Personal communication with Dr. Ted Shugar, Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, CA, December 1978.

32. "Replacing Oil and Natural Gas with Coal: Prospects in the Manufacturing Industries," The Congress of the United States Congressional Budget Office, US CON CBO, August 1978.

33. Rifas, B. E., and S. J. White, "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond," EPRI EA-237, Project 437-1, Prepared by Manalytics, Inc., September 1976.

34. Nagarvala, P. J., O. C. Ferrell, and L. A. Olver, "Regional Energy System for the Planning and Optimization of National Scenarios Response, Final Report; Clean Coal Energy: Source-to-Use Economics Project," Bechtel Corporation, prepared for ERDA, Contract No. ERDA-76-109, June 1976.

35. Detman, R., "Factored Estimates for Western Coal Commercial Concepts," FE-2240-5, C. F. Braun and Co., Alhambra, CA, prepared for ERDA Contract No. E (49-18)-2240, October 1976.

36. "Biomass Energy for Hawaii," prepared by the Stanford University-University of Hawaii Biomass Energy Study Team, Institute for Energy Studies, Stanford, CA, February 1977.

APPENDIX A

COST AND PERFORMANCE CHARACTERIZATION OF ALTERNATE ENERGY SYSTEMS

Appendix A discusses in detail the conventional and alternate energy systems modeled in the NES optimization program. For each system, the energy conversion process is described, relevant cost and performance data is tabulated, and the equations used by the NES code to simulate energy system operation are given.

A.1 CONVENTIONAL ENERGY SOURCES

The Navy Energy Siting (NES) optimization code separates energy demand into three end-use categories: heating, process steam, and electricity. Various energy systems associated with each energy-use sector compete on an economic basis ($\$/10^6$ Btu) with conventional systems to meet demand at minimum cost. This approach assumes energy consumption is constant from year to year (reduction in demand by conservation is not considered an option), and all energy demand is satisfied. Thus, demand for conventional energy equals that portion of the total energy demand not met by alternative energy sources. As such, conventional energy sources serve in a peaking capacity, typically at low capacity factors (ratio of actual energy produced to potential energy produced).

This section describes the conventional energy systems which compete in the three energy use sectors.

Space Heating and Hot Water

Presently, space heating and hot water at Navy bases is supplied by either decentralized boilers or central powerplants, each fired with either natural gas or fuel oil. Many of these decentralized boilers are old and inefficient (Reference A-1). This study assumed that all existing boilers will be replaced with modern, decentralized boilers fired with Number 6 fuel oil.

Heating demand varies tremendously during the year in response to seasonal variations. However, this study stipulated that the entire heating demand must be satisfied by either alternative energy sources or oil-fired boilers. Consequently, boilers must be sized to meet the maximum hourly peak demand (10^6 Btu/hr) remaining after alternative

energy systems have contributed to the heating sector. Thus, on the average, only 50 percent of boiler capacity is required. Boiler efficiency (ratio of heat output to Btu content of fuel oil input) was assumed to be 80 percent.

Analogous to investment in alternative energy sources, the boiler capital cost is depreciated at a 10 percent discount rate over a 25-year lifetime (see Section 3.3). Cost and peformance data are listed in Table A-1.

A.1.2 Process Steam

Currently, process steam is supplied by either a central powerplant or decentralized boilers, depending upon the requirements of a particular base. As in the approach taken for the heating sector, this study assumed that all existing steam equipment is replaced by decentralized boilers fired with Number 6 fuel oil. Similarly, boilers were sized to meet the maximum hourly peak demand remaining after alternative energy systems have contributed to the process steam sector.

Again, capital cost is depreciated over a 25-year system life. Table A-1 describes cost and performance data for the process steam equipment.

A.1.3 Electricity

Electrical demand not met by alternative energy sources is purchased from local utility companies at rates suggested by CEL, Port Hueneme. As recommended by NAVFAC, electricity costs were inflated at a differential rate of 6 percent/year.

Electricity is assumed to be available in unlimited supply, and no penalty is charged for electricity consumption during periods of peak demand. Actually, cost for peaking power may be substantially higher than baseload power. However, this variation in cost was neglected.

TABLE A-1. COST AND PERFORMANCE DATA: CONVENTIONAL ENERGY SOURCES

Energy Sector	System Description	Capital Cost Factor	Operation and Maintenance Cost	Efficiency[a]	References
Space Heating and Hot Water	Decentralized boilers fired with Number 6 fuel oil	$12,611/(10^6 Btu/hr)	50% annualized capital cost[b]	80%	A-1
Process Steam	Decentralized boilers fired with Number 6 fuel oil	$16,433/(10^6 Btu/hr)	50% annualized capital cost[b]	72%[c]	A-1
Electricity	Purchased from local utility	N/A	N/A	N/A	

[a]Efficiency defined as the ratio of heat output to Btu content of fuel input.
[b]See Section 2.2.3.
[c]Assumes boiler efficiency of 80 percent with 10 percent distribution losses.
N/A = Not applicable.

T-1880

A.2 REFUSE DERIVED FUEL (RDF)

A.2.1 Introduction

Refuse can be used as an energy source either directly, as in incineration, to produce steam; or indirectly, as in pyrolysis, to produce a gaseous or liquid fuel. In broad terms, refuse refers to residential and commercial garbage, agricultural and industrial waste, discarded package material (wooden crates), and forestry residue (biomass). Unless otherwise stated, this report will define refuse as solid municipal garbage produced by a Navy base or refuse available from sources neighboring the base (within a 15-mile radius). Liquid waste will not be considered. Municipal refuse typically consists of 70 to 90 percent combustibles such as paper, wood, and plastic; the remainder consists of noncombustibles such as glass, ferrous metals, and aluminum. On the average, refuse has an energy content of approximately 4,500 Btu/lbm (Reference A-2).

Incineration, pyrolysis, anaerobic digestion, and combustion can be used to recover energy from solid wastes and residues. The simplest and most economical approach is to incinerate the refuse in a waterwalled combustion chamber to produce steam. Pyrolysis is the thermal decomposition of organic compounds in the absence or near absence of oxygen. Pyrolysis yields a low Btu gas (150 Btu/ft^3) consisting of hydrogen, methane, and carbon dioxide or a liquid with a heat content approximately 65 percent of No. 6 fuel oil. Thus, pyrolysis produces a storable fuel. Anaerobic digestion is the decomposition of refuse by bacteria into equal quantities of methane and carbon dioxide. Although proven technically on an experimental basis, anaerobic digestion has not been tested commercially.

In addition to the methods described above, refuse can be co-combusted with coal or natural gas in utility powerplants. This requires modification of the boiler fuel feed system and ash removal equipment to handle the increased flowrate of low-density refuse. This study chose to model the incineration of prepared solid refuse to meet process steam, heating, and electrical demands because the technology is proven, and commercial facilities are available to provide adequate capital cost, operating cost, and performance data. A detailed description of the model used is given in the remaining portion of this section.

A.2.2 Process Description for RDF

Figure A-1 illustrates the process flow diagram for a refuse-fired waterwalled boiler. A municipal garbage truck delivers refuse which is initially separated by an air classifier, according to density, into combustibles and noncombustibles. Then, a magnet is used to separate noncombustibles into: (1) ferrous metals; and (2) dirt, glass, aluminum, and other nonferrous metals. Although this preprocessing consumes a significant amount of energy (30 kWh/ton compared with 10 kWh/ton required for no processing, Reference A-2), it permits the shredded refuse to be suspension fired, which increases combustion efficiency and improves reliability. In addition, the recovered metals can be sold as scrap and charged as revenue to the RDF plant. Remaining inert material is taken to a landfill.

RDF plants are capable of producing steam at pressures and temperatures ranging from 175 psig and 370°F to 1250 psig and 905°F (Reference A-2). Cyclone and electrostatic precipitators remove ash and other particulates from the by-product gas stream. Refuse-fired boilers are presently operating in Chicago, St. Louis, Nashville, and the Navy facility at Norfolk, Virginia.

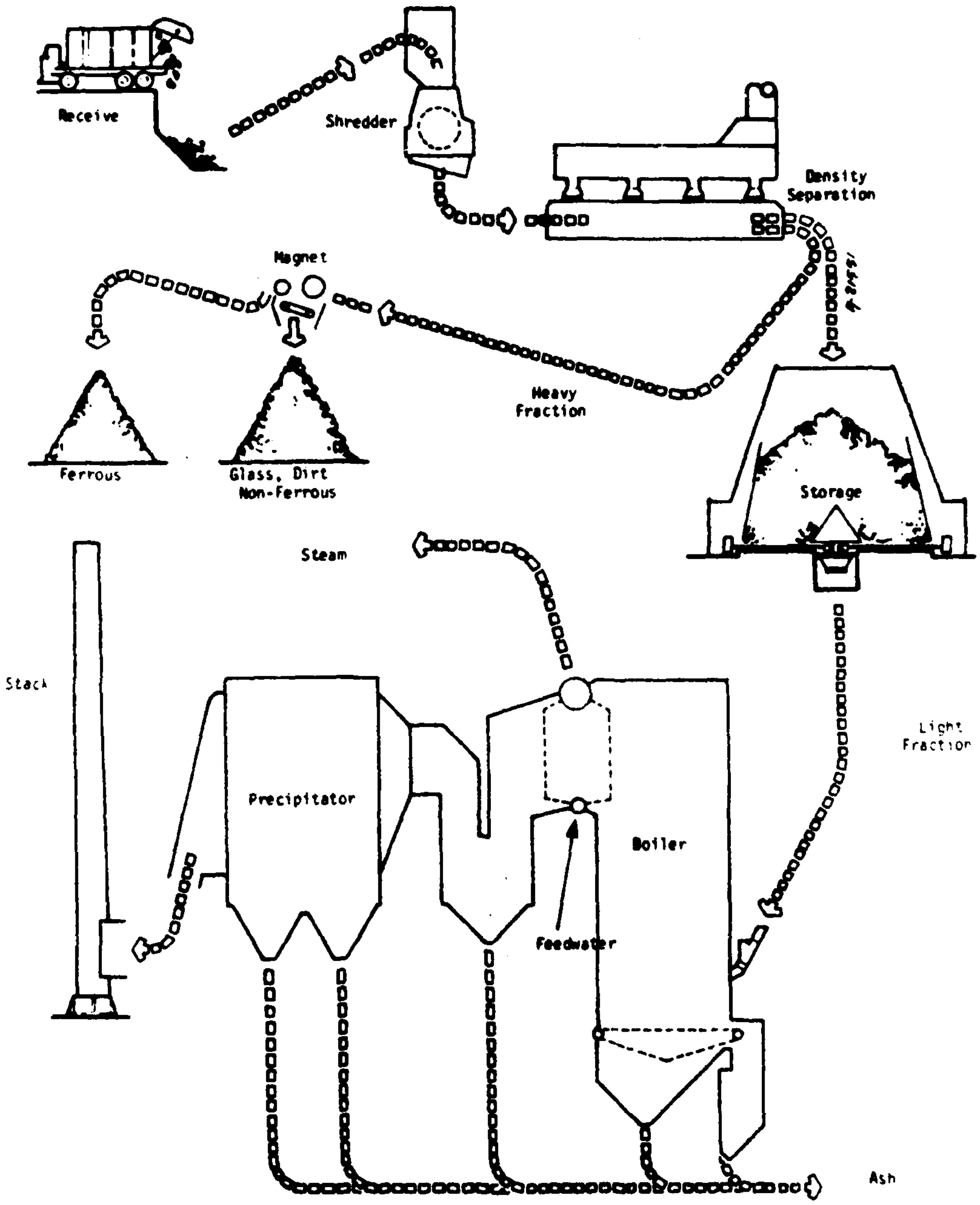

Figure A-1. Flow diagram RDF facility (Reference A-3).

A.2.3 Computer Model for RDF

Figure A-2 presents a schematic diagram of the inputs, outputs, and parameters of the RDF computer subroutine.

The equations used by the RDF steam and electricity computer subroutines to calculate performance and costs are listed below. The numerical values of the parameters input to the steam and electricity model are discussed in Table A-2 and Table A-3, respectively.

Calculations: RDF Steam Model

$$\begin{pmatrix}\text{Annual}\\ \text{Steam Output}\\ \text{MBtu/yr}\end{pmatrix} = \begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \times \begin{pmatrix}\text{Refuse}\\ \text{Heating}\\ \text{Value}\\ \text{Btu/lbm}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix} \times \begin{pmatrix}2000 \times 365 \times 10^{-6}\\ \frac{\text{lbm}}{\text{ton}} \times \frac{\text{day}}{\text{yr}} \times \frac{\text{MBtu}}{\text{Btu}}\end{pmatrix} \quad \text{(A-1)}$$

$$\begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \text{Factor}\\ \$/(\text{ton/day})\end{pmatrix} \times \left[\begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix}\right]^{\text{Exponent}} \quad \text{(A-2)}$$

$$\begin{pmatrix}\text{Revenue}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Value}\\ \text{Recovered}\\ \text{Material}\\ \$/\text{ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \times \begin{pmatrix}365\\ \text{day/yr}\end{pmatrix} \quad \text{(A-3)}$$

$$\begin{pmatrix}\text{Trans.}\\ \text{Cost}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Average}\\ \text{Miles Refuse}\\ \text{Transported}\\ \$/\text{mile-ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \times \begin{pmatrix}365\\ \text{day/yr}\end{pmatrix} \times \begin{pmatrix}\text{Total}\\ \text{Miles}\end{pmatrix} \quad \text{(A-4)}$$

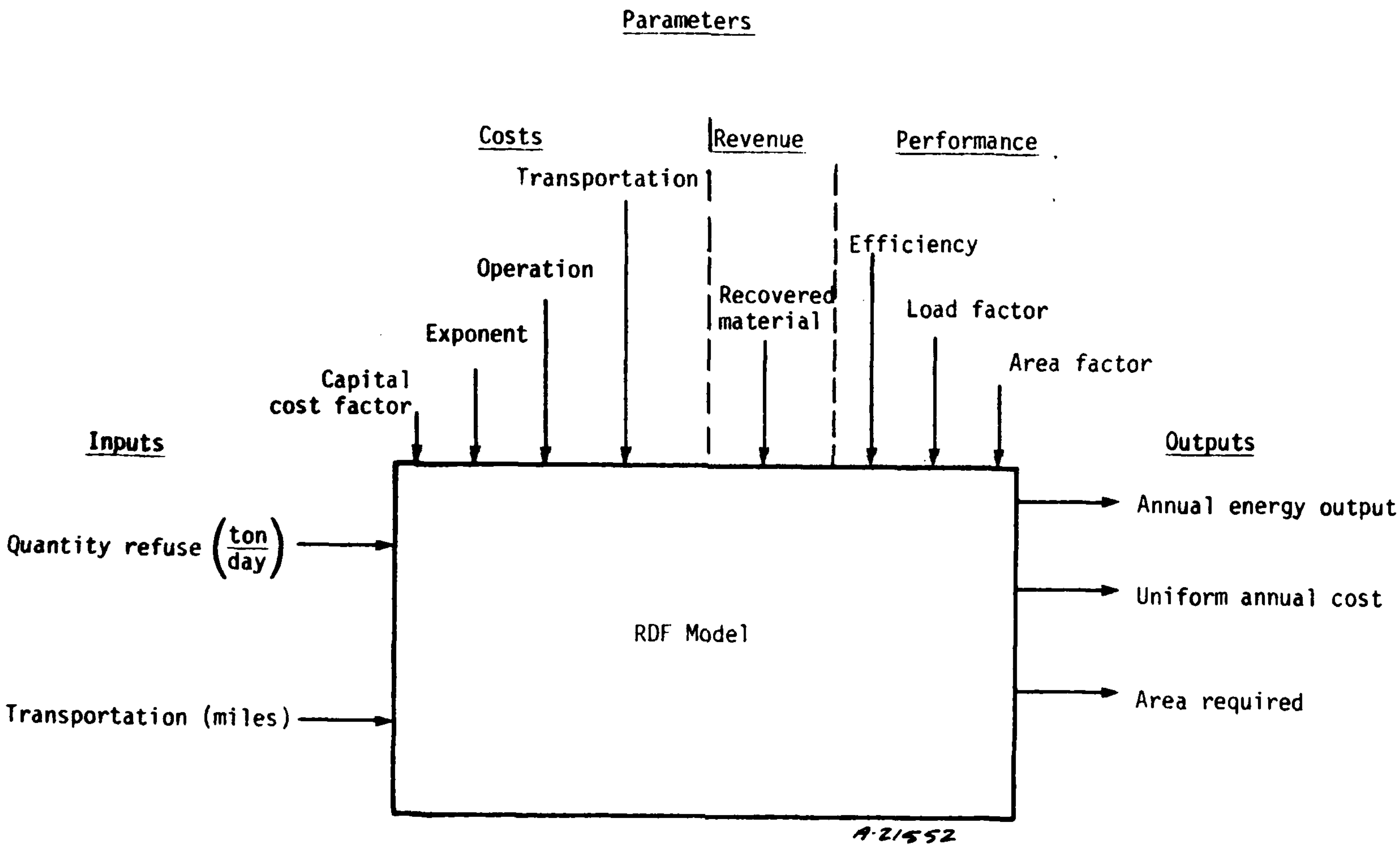

Figure A-2. Schematic diagram for RDF model.

TABLE A-2. PERFORMANCE AND COST DATA -- RDF STEAM MODEL

	Numerical Value	Comments	References
<u>Performance Data</u>			
Efficiency[a]	55%	In practice, efficiency ranges from 50% to 70%.	A-2, A-4, A-5
Load Factor[b]	80%	Difficulties in material handling, variations in refuse composition, potential corrosion problems	A-2
Heating Value of Refuse	4500 Btu/lbm	Varies widely with refuse composition and moisture content	
Area Factor	330 ft^2/ton/day	Assuming: (1) a 5-day supply of refuse stored as a conical pile with 20^{o} angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the refuse pile.	A-6
<u>Cost Data</u>			
Capital Cost Factor	\$27,000 per $\frac{\text{ton/refuse}}{\text{day}}$	Cost estimates vary widely from \$10,000 per (ton/day) to \$135,000 (ton/day).	A-2, A-7, A-4 A-8
Exponent	1.0	Due to large variations in capital cost, economies of scale could not be determined in a reasonable manner.	
Operating Cost	\$18.57/ton-refuse		A-2, A-8
Transportation Cost	--	Not currently available	
Revenue	\$7.80/ton-refuse	Revenue received from this sale of noncombustibles (iron, aluminum, glass)	A-8

[a]The efficiency of an RDF plant is defined as the ratio of the thermal value of the output steam to the thermal value of the input refuse.
[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

A-1877

TABLE A-3. PERFORMANCE AND COST DATA -- RDF ELECTRICITY MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency[a]	23%	Steam turbine efficiency taken as approximately 42%	A-2, A-4, A-5, A-9
Load Factor[b]	80%	Difficulties in material handling, variations in refuse composition, potential corrosion problems	A-2
Heating Value of Refuse	45,000 Btu/lb	Varies widely with refuse composition and moisture content	
Area Factor	330 ft^2/ton/day	See area factor Table A-2.	A-6
Cost Data			
Capital Cost Factor Steam Plant	\$27,000 per $\frac{\text{ton/refuse}}{\text{day}}$	Assume identical RDF-steam capital cost.	A-2, A-4, A-7, A-8
Capital Cost Factor Turbine Generator	\$250,000 per MW		A-10
Exponent	1.0	No economies of scale	
Operating Cost	\$18.57/ton-refuse		A-2, A-7, A-8
Transportation Cost	--	Not currently available	
Revenue	\$7.80/ton-refuse	Revenue received from the sale of noncombustibles (iron, aluminum, glass)	A-8

[a]The efficiency of an RDF plant is defined as the ratio of the thermal value of the output steam to the thermal value of the input refuse.
[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

A-1878

$$\begin{pmatrix}\text{Maintenance}\\ \text{Cost}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Maintenance}\\ \text{Cost}\\ \$/\text{ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \times \begin{pmatrix}365\\ \text{day/yr}\end{pmatrix} \tag{A-5}$$

$$\begin{pmatrix}\text{Area}\\ \text{Required}\\ \text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\ \text{Factor}\\ \text{ft}^2/(\text{ton/day})\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ \text{ton/day}\end{pmatrix} \tag{A-6}$$

Calculations: RDF Electricity Model

Except for unit changes from MBtu to MWh, and the calculation of capital cost, the equations required to calculate the performance and cost of the RDF electricity model are identical to the RDF steam model discussed in the previous section.

$$\begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \text{Factor}\\ \$/(\text{ton/day})\end{pmatrix} \times \left[\begin{pmatrix}\text{Quantity}\\ \text{Refuse}\\ (\text{ton/day})\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix}\right]^{\text{Exponent}} + \begin{pmatrix}\text{Turbine}\\ \text{Cost}\\ \$/\text{MW}\end{pmatrix} \times \begin{pmatrix}\text{Turbine}\\ \text{Size}\\ (\text{MW})\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix} \tag{A-7}$$

A.3 GEOTHERMAL

A.3.1 Introduction

Geothermal energy is a little understood, and even less exploited, natural energy source. Only within the last 10 to 15 years has geothermal energy been harnessed to produce electrical power. Renner, White, and Williams (Reference A-11) estimated the heat stored in identified geothermal high temperature ($T_{H_2O} > 150^{\circ}C$) hot water convection systems to total 0.944×10^8 Btu, while undiscovered geothermal hot water

convection systems may hold five times that value in stored energy. Geothermal energy results from either: (1) heat released from surface volcanic sources (in particular, high silica varieties of volcanic rock), or (2) regional geothermal temperature gradients resulting from conductive heat transfer from the earth. Unfortunately, geothermal reservoirs are restricted primarily to Alaska and the Western states of California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, and Washington. In fact, 60 percent of the western geothermal reserves are located in California (Reference A-10).

Geothermal reservoirs are generally classified as steam, hot water, or dry heat (hot rock). Some vapor-dominated systems, although rare, generate dry steam which can be converted directly into electricity utilizing turbine generators. The Geysers (California) and Larderelle (Italy) are examples of geothermal systems which produce superheated steam. Wet steam, containing dissolved gases (H_2S) and minerals, requires the geothermal fluids to be passed through heat exchangers which provide heating of "clean" water that subsequently drives turbine generators. Hot water systems range in temperature from ambient to 360°C and are typically divided into three temperature ranges according to potential applications:

1. $T_{water} > 150^{o}C$ -- Water with temperatures greater than 150°C can be economically used for electric power. Depending upon such parameters as the quantity of dissolved gases and minerals, temperature, and pressure, the hot water is either flashed under vacuum with the resulting vapors passed through turbine generators, or the water is passed through heat exchangers which transfer thermal energy to an organic working fluid that drives a turbine generator.

2. $150^{o}C > T_{water} > 90^{o}C$ -- Reservoir water can heat process fluids for space heating, domestic hot water, or process heating, but it is not capable of generating electricity economically.

3. $T_{water} < 90^{o}C$ -- Due to heat losses in pipe distribution system, geothermal water with temperature less than $90^{o}C$ can be used only for space heating and domestic hot water where buildings are located on a geothermal reservoir.

In contrast to geothermal hot water reservoirs, energy is extracted from dry heat geothermal reservoirs by circulating water down into a well in a closed loop. This method is used in Klamath Falls, Oregon to provide domestic hot water and space heating for commercial and residential buildings (Reference A-12).

The performance and costs of hot rock and hot water geothermal systems with temperatures less than $150^{o}C$ are strongly dependent upon the reservoir characteristics and the particular system design. Because this study is based upon general energy conversion systems whose performance and costs are relatively independent of site characteristics, hot rock systems will not be modeled. However, steam and hot water (temperatures $> 150^{o}C$) geothermal reservoirs are both modeled to meet process steam, space heating, and electricity energy demand. These systems will be discussed in the following sections.

A.3.2 <u>Process Description for Geothermal Conversion into Electricity and Steam</u>

For dry steam geothermal reservoirs, steam can be extracted directly from the ground and passed through a turbine generator to produce electricity. For hot water (temperatures $> 150^{o}F$) geothermal

reservoirs, if sufficient pressure exists (50 psia), the water can be flashed under vacuum into steam which can drive turbine generators (Figure A-3).

For hot water systems without sufficient pressure, thermal energy is extracted with a heat exchanger from the reservoir water to drive an organic-working fluid turbine generator cycle (Figure A-4). A study conducted by EPRI (Reference A-13) has concluded that for hot water systems, a binary cycle rather than a flash steam conversion process is recommended, due to its broad application to reservoirs with temperatures in the range of 150^{o}C to 200^{o}C. In addition, the cost and performance of both systems are approximately the same. Consequently, the hot water performance data is based upon an average value for both binary cycle and flash steam performance.

A.3.3 Computer Model for Geothermal

Figure A-5 presents a schematic diagram of the inputs, outputs, and parameters of the RDF computer subroutine.

The equations used to determine the performance and cost of the geothermal electricity model are listed below. Except for energy unit changes from MWh to MBtu, the equations used by the geothermal steam model are identical to the geothermal electricity model. The numerical values of the parameters used by the geothermal electricity model and the steam model are discussed in Tables A-4 and A-5, respectively.

Calculations

$$\begin{pmatrix}\text{Annual}\\ \text{Electrical}\\ \text{Output}\\ \text{MWh/yr}\end{pmatrix} = \begin{pmatrix}\text{Reservoir}\\ \text{Capacity}\\ \text{MWh/yr}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix} \qquad \text{(A-8)}$$

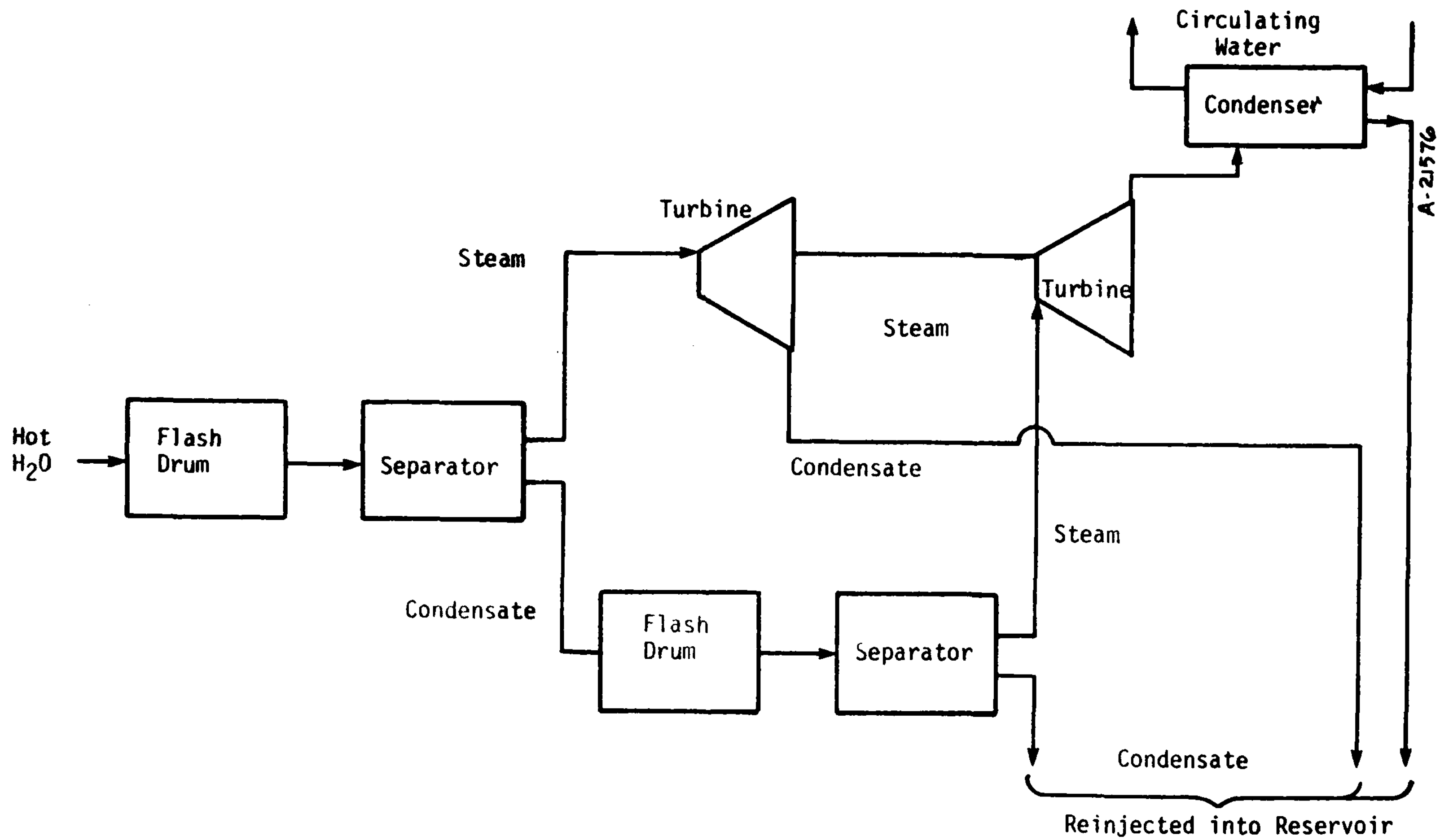

Figure A-3. Two stage flash steam powerplant.

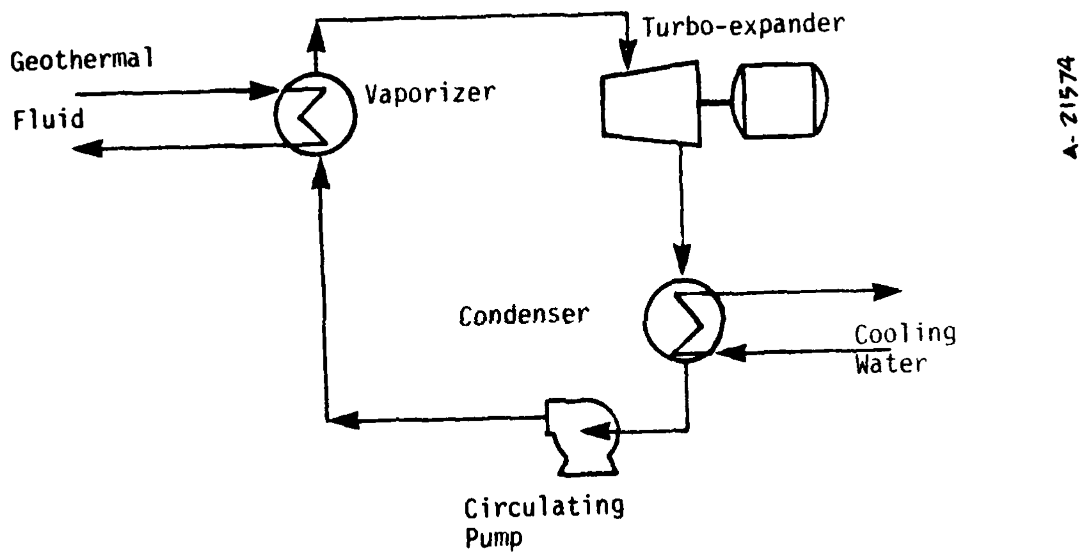

Figure A-4. Simple binary cycle.

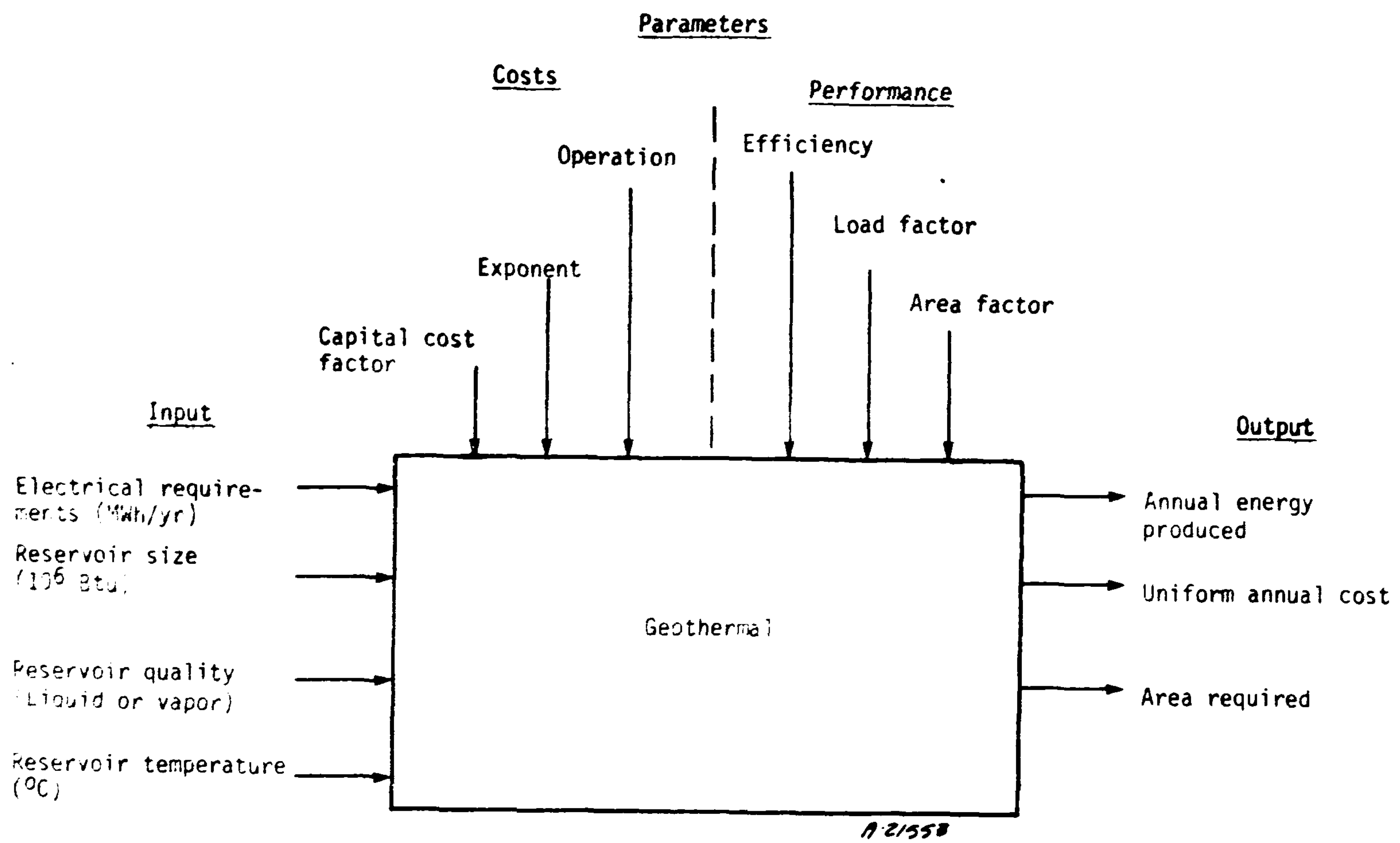

Figure A-5. Schematic diagram for geothermal model.

TABLE A-4. PERFORMANCE AND COST DATA -- GEOTHERMAL ELECTRICITY MODEL

	Numerical Value	Comments	References
Performance Data			
Reservoir Capacity[a]	25%[b] Reservoir Size	Geothermal reservoir size given by Renner, White, and Williams. Reservoir lifetime assumed to be 40 years.	A-11
Efficiency[c]	20%	Vapor-dominated system	A-13, A-14
	10% to 20%	For water-dominated systems, efficiency depends on the reservoir temperature (Figure A-6).	A-13, A-14
Load Factor[d]	90%		
Area Factor	21,800 ft^2/MW	The area required for a geothermal conversion facility, including area necessary for well sites (5 acres per megawatt installed capacity)	A-15
Cost Data			
Capital Cost Factor	\$2.5 x 10^6 MW	Includes cost of exploration, drilling, and conversion facility	A-13, A-15
Exponent	0.85		A-15
Operating Cost	(Figure A-7)	Operating Cost (\$/MWh) is a decreasing function of powerplant size (MW).	A-15

T-1881

[a]Geothermal reservoir capacity is defined as the ratio of recovered energy (percent of reservoir size) to reservoir lifetime.
[b]Estimation of the thermal energy production capacity of a geothermal reservoir depends upon: (1) the fraction of the hydrothermal convection system which is porous and permeable, and (2) the fraction of the heat stored in that portion which is recoverable at the surface. Matherson and Muffler (Reference A-14) estimate that 50% of the reservoir is porous and permeable, and that 50% of the available energy is recoverable at the surface.
[c]The efficiency of a geothermal plant is defined as the ratio of the electrical energy produced to the thermal energy of liquid or vapor extracted from the reservoir.
[d]Load factor is defined as the fraction of time a powerplant actually produces energy.

TABLE A-5. PERFORMANCE AND COST DATA -- GEOTHERMAL STEAM MODEL

	Numerical Value	Comments	References
Performance Data			
Reservoir Capacity	25% Reservoir Size	(Refer to Table A-4)	A-11
Efficiency[a]	80%	Typical heat exchanger efficiency	
Load Factor[b]	90%		
Area Factor	21,800 ft^2/MW	(Refer to Table A-4)	A-15
Cost Data			
Capital Cost Factor	\$155/(MBtu/hr)	Capital cost of a steam generating system is 80% of the capital cost of an identical electricity generating system	A-8, A-13, A-15
Exponent	0.85		A-15
Operating Cost	(Figure A-8)	Operating cost (\$/10^6 Btu) is a decreasing function of plant size (10^6 Btu/yr)	A-15

A-1882

[a]The efficiency of a geothermal steam plant is defined as the ratio of the steam energy produced to the thermal energy of liquid or vapor extracted from the reservoir.
[b]Load factor is defined as the fraction of time a powerplant is designed to produce energy.

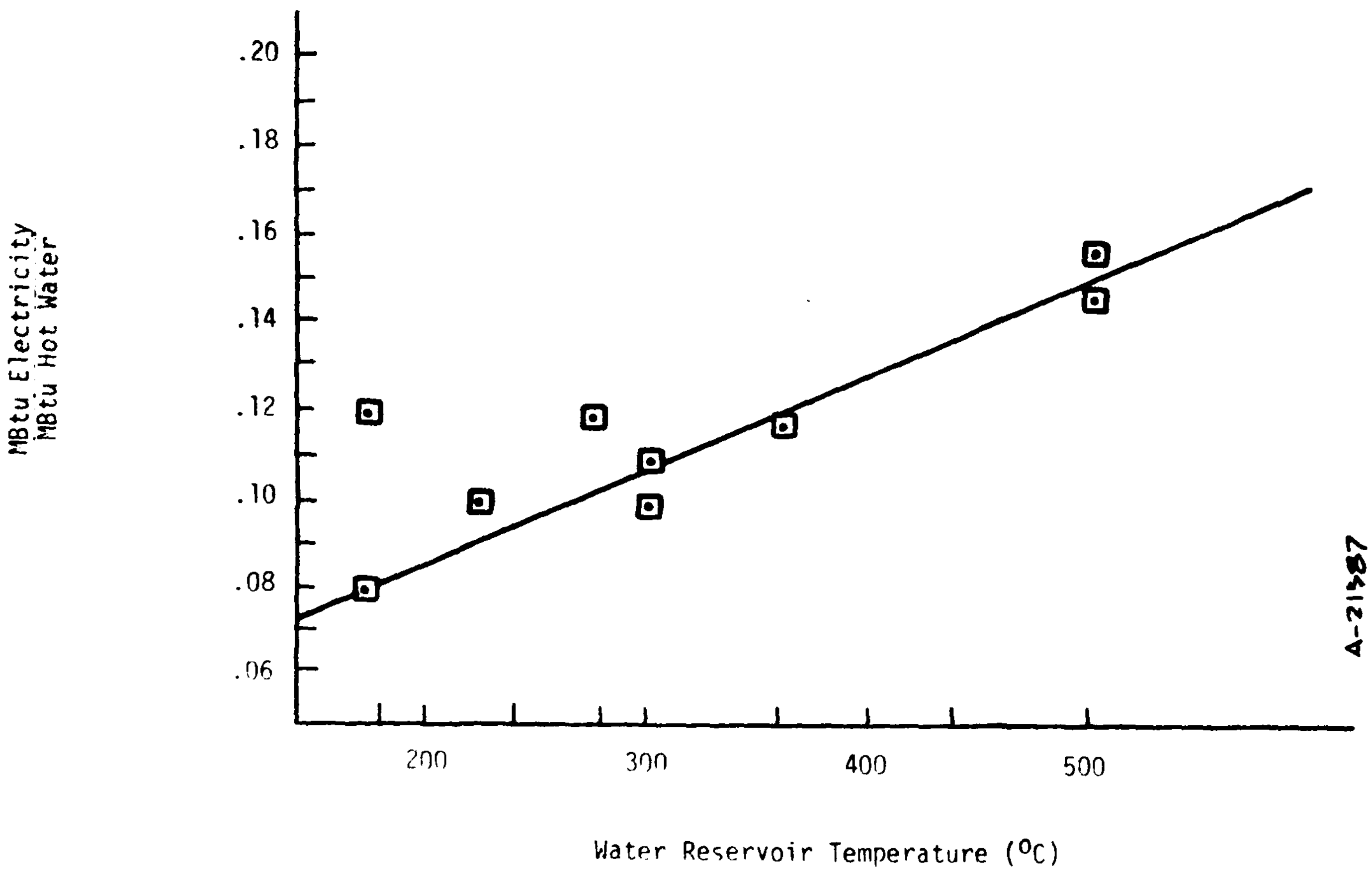

Figure A-6. Geothermal efficiency vs. reservoir temperature (hot water reservoir) (References A-13, A-14).

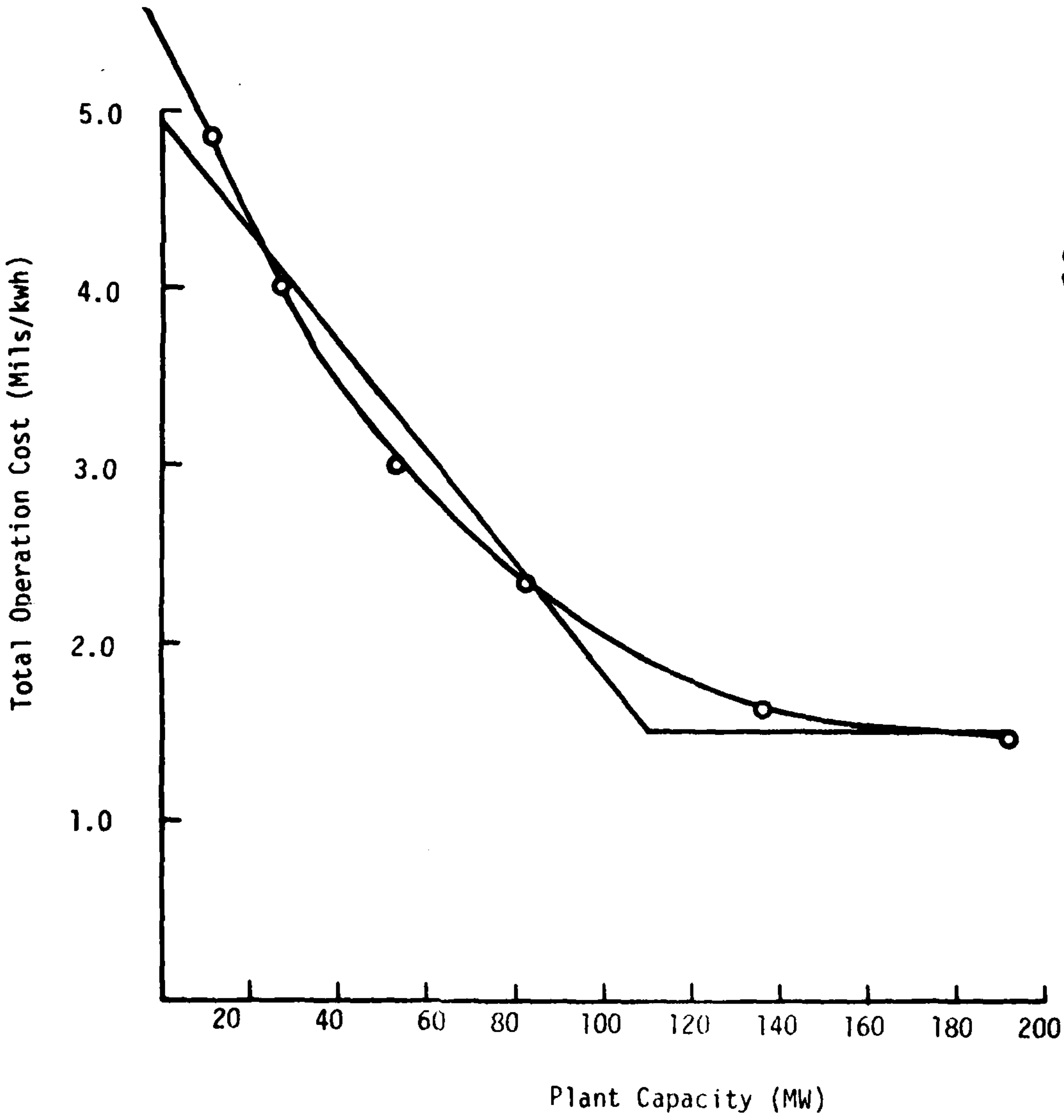

Figure A-7. Electric geothermal operating cost vs. powerplant capacity (Reference A-15).

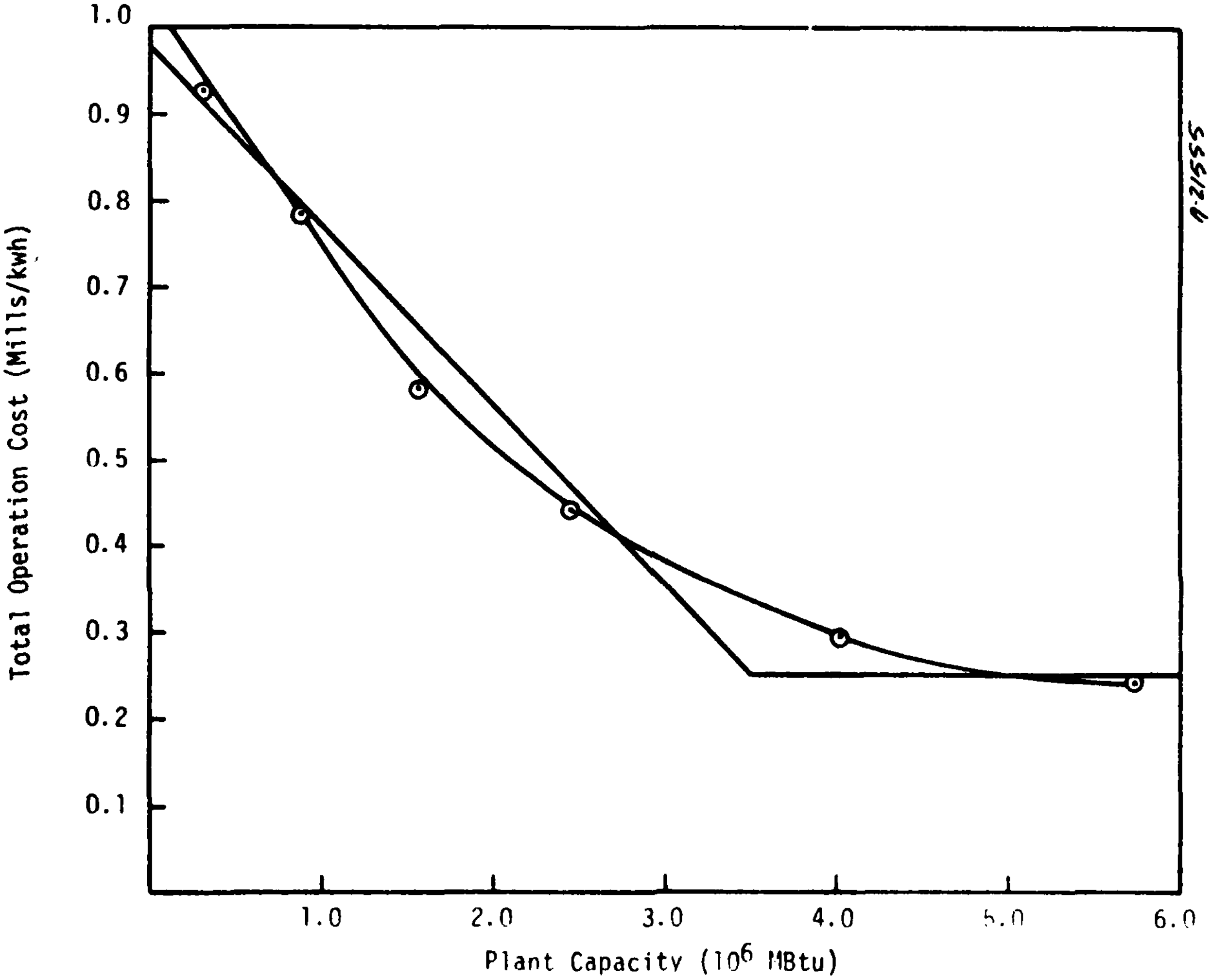

Figure A-8. Geothermal steam operating cost vs. powerplant capacity (Reference A-15).

$$\begin{pmatrix}\text{Capital}\\\text{Cost}\\\$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\\text{Cost}\\\text{Factor}\\\$/\text{MW}\end{pmatrix} \times \left[\begin{pmatrix}\text{Electric}\\\text{Powerplant}\\\text{MW}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\\text{Factor}\end{pmatrix}\right]^{\text{Exponent}} \quad \text{(A-9)}$$

$$\begin{pmatrix}\text{Annual}\\\text{Operating}\\\text{Cost}\\\$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Operating}\\\text{Cost}\\\$/\text{MWh}\end{pmatrix} \times \begin{pmatrix}\text{Annual}\\\text{Electrical}\\\text{Output}\\\text{MWh/yr}\end{pmatrix} \quad \text{(A-10)}$$

$$\begin{pmatrix}\text{Area}\\\text{Requirements}\\\text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\\text{Factor}\\\text{ft}^2/\text{MW}\end{pmatrix} \times \begin{pmatrix}\text{Electric}\\\text{Powerplant}\\\text{Size}\\\text{MW}\end{pmatrix} \quad \text{(A-11)}$$

A.4 COAL

A.4.1 Introduction

With increasing restrictions on foreign supplies of crude oil, the United States must rely more heavily upon national energy sources, particularly coal. Demonstrated bituminous and lignite coal reserves in the United States are 8.7 x 10^{18} Btu compared with 0.22 x 10^{18} Btu of proven and indicated reserves of crude petroleum (Reference A-16). The Navy's emphasis on energy self sufficiency will mandate the use of coal as a future Navy baseload energy source.

There are a number of methods for converting crude coal into a usable energy form. These include: conventional combustion, cogeneration, fluidized bed combustion, gasification, and liquefaction. Conventional combustion includes suspension or grate firing of coal in a water-walled boiler to produce steam which can be subsequently converted to electricity by passing the steam through a condensing turbine. In addition, simultaneous generation of electricity and process steam (cogeneration) is possible by passing steam through an extraction turbine.

In fluidized bed combustion (FBC), heat transfer to boiler tubes is improved by burning coal in a bed of suspended granular solids. Electricity is produced by using steam turbines and/or flue gas turbines.

Exposing pulverized coal to high pressure oxygen (the Lurgi process), or a high temperature and high pressure oxygen-steam mixture (the Hygas and BI-Gas process) yields a low-Btu gas (300 Btu/ft^3) composed primarily of CO_2, CO, CH_4, and H_2. In contrast, high-Btu gas (900 Btu/ft^3) can be produced by exposing coal directly to hydrogen gas (the Hydrane process).

Coal may be converted to clean-burning liquid fuel by the Synthoil process which involves reacting hydrogen with a coal-oil slurry in a turbulent flow, packed bed reactor.

This study considers the production of steam and electricity by conventional coal combustion, cogeneration, and fluidized bed combustion. This section discusses the technical and economic aspects of conventional coal combustion and fluidized bed combustion. Cogeneration will be discussed separately in Section A-7.

A.4.2 Conventional Coal Combustion

There are two primary methods of conventional coal combustion: pulverized-coal systems and stoker systems. For pulverized-coal systems, a mixture of pulverized coal and air is delivered tangentially into the furnace where combustion occurs completely in suspension. Premixing fuel and air permits use of lower excess air which improves combustion efficiency. Pulverized-coal combustion is a continuous operation, sensitive to demand fluctuations. As a result, stable operation is possible only within strict design limitations.

In contrast, for stoker systems, coal combustion occurs both in suspension and on a moving grate located at the bottom of the furnace. Combustion on the grate enables a stoker to handle wide load fluctuations, but, compared to pulverized-coal systems, requires greater amounts of excess air which reduces combustion efficiency.

Suspension firing of pulverized coal, which requires complicated and expensive coal preparation and handling equipment, is generally used at larger boiler sizes. Suspension firing is considered economical at unit sizes greater than 100,000 to 200,000 lbm steam/hr (Reference A-17 and A-18). Stoker firing is used at smaller sizes. In addition, stokers

are often preferred because of their greater operating range, capacity to burn a wider range of solid fuels, and lower auxiliary power requirements.

The largest-size Navy process steam or electric power facility is approximately 200,000 lbm steam/hr. Consequently, this study chose to model stoker-fired furnaces as the method of conventional coal combustion.

A.4.2.1 Process Description -- Conventional Coal Production of Electricity and Steam

Stoker-fired coal combustion systems consist of three basic components: (1) boiler, (2) pollution control equipment, and (3) coal and ash handling equipment. These components are discussed below.

Boiler

Spreader stokers deliver fuel into the furnace over the fire with a uniform spreading action, permitting suspension burning of the fine fuel particles. Larger particles (approximately 50 percent of the total) fall to the grate at the bottom of the furnace and combust in a thin fast-burning bed. A traveling grate insures thorough mixing of coal particles and continuously discharges ash which accumulates on the grate.

Water-cooled walls absorb radiant and convective heat from the combustion flames. A superheater absorbs the remaining sensible heat in the flue gas. This absorbed thermal energy converts water to steam which can be used directly for industrial process applications, or passed through a turbine-generator to produce electricity. A stoker-fired boiler is illustrated in Figure A-9.

Pollution Control Equipment

Coal combustion energy sources are required to meet proposed Federal Stationary Source Standards. Flue gas desulfurization (FGD), electrostatic precipitators (ESP), and staged combustion (SC) were

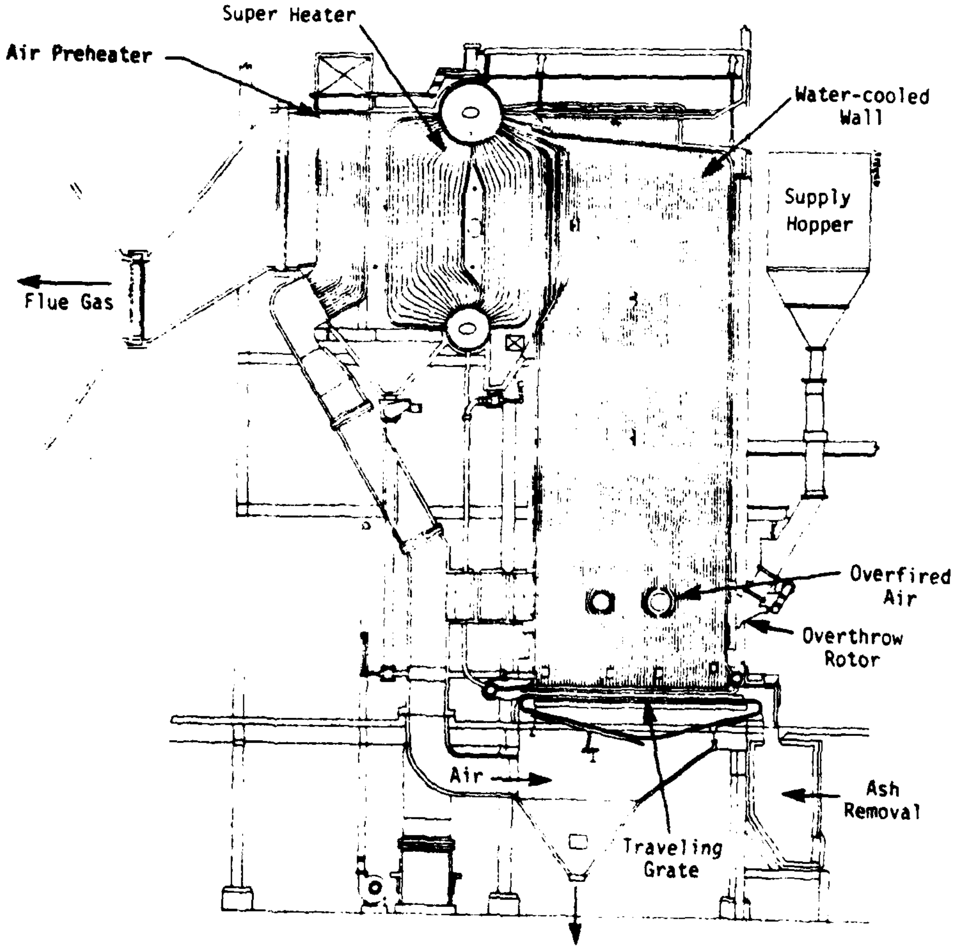

Figure A-9. Stoker-fired boiler.

selected to control SO_2, particulates, and NO_x emissions, respectively. The Federal Standards for these pollutants are listed in Table A-6.

TABLE A-6. PROPOSED FEDERAL STATIONARY SOURCE STANDARDS

Pollutant	Standard
SO_2	1.2 lbm/10^6 Btu coal burned
Particulates	0.03 lbm/10^6 Btu
NO_2	0.50 lbm/10^6 Btu - Subbituminous Coal 0.60 lbm/10^6 Btu - Bituminous Coal

(Reference A-19)

A brief description of the pollution control equipment follows:

- FGD -- Flue gas from the furnace is passed counter-currently through a limestone ($CaCO_3$) slurry which reacts with the SO_2 to form calcium sulfate ($CaSO_4 \cdot 2H_2O$). The calcium sulfate is subsequently dried and disposed in a landfill. State-of-the-art processes exist which can recover the limestone for further use and produce sulfuric acid as a by-product. These processes are presently being commercialized.
- ESP -- Particulates in the gaseous effluent from a furnace are electrostatically charged. Consequently, opposing electrically charged metal plates attract these particles as they pass between them, effectively removing them from the effluent stream. Plate area required for adequate removal of particulates depends on the magnitude of charge on the particles. A larger charge requires less area. SO_2

contained in the effluent stream increases particle charge, thereby reducing plate area which lowers capital cost.

- SC -- NO_x control methods are in an early stage of development. However, by staging combustion and using low NO_x burners, NO_x emissions can be reduced. This typically requires only minor modification of the boiler.

The capital cost, maintenance cost, and performance of FGD and ESP vary depending on coal composition, particularly sulfur content. For simplicity, coal was divided into two types: Eastern-high sulfur coal (1.27 lbm sulfur/10^6 Btu) and Western-low sulfur coal (0.81 lbm sulfur/ 10^6 Btu). Based on these coal compositions, FGD and ESP were designed (sized) to meet federal emission standards. Capital cost of FGD increases with SO_2 concentration. In contrast, ESP capital cost decreases significantly with SO_2 concentration because SO_2 in the furnace gaseous effluent increases particle electrostatic charge, requiring less plate area, and thereby reducing capital cost. Consequently, FGD and ESP capital cost tend to cancel each other with changes in coal sulfur content. The net result is slightly decreased capital cost of pollution abatement equipment with increasing coal sulfur content. These differing costs are included in the capital cost figures listed in Table A-7.

Coal and Ash Handling Equipment

Unprocessed, 1-inch diameter coal is initially crushed to 1/4 inch size, then transported by conveyer belt to supply hoppers located above the furnace. Gravity feeds the coal to an overthrow rotor which evenly distributes the coal over the furnace area (Figure A-9).

During combustion, ash collects on the grate at the bottom of the furnace. The moving grate continuously discharges the ash into an ash hopper located below and to the side of the furnace. The ash is then trucked to a landfill for final disposal.

A.4.2.2 Computer Model for Conventional Coal Combustion

Figure A-10 presents a schematic diagram of the inputs, outputs, and parameters of the conventional coal computer subroutine. The specific equations used by the conventional coal electricity computer subroutine to calculate performance and cost are listed below. Except for unit changes from MWh to MBtu, the equations required to calculate performance and cost of the conventional coal steam model are the same as the equations for the conventional coal electricity model (less turbine cost). It is assumed that the steam model can meet both the process steam and the space heating energy demand. Data input to the electricity and steam models are discussed in Tables A-7 and A-8, respectively.

Calculations

$$\begin{pmatrix}\text{Annual}\\ \text{Electrical}\\ \text{Output}\\ \text{MWh/yr}\end{pmatrix} = \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}\text{Btu}\\ \text{Content}\\ \text{Coal}\\ \frac{\text{Btu}}{\text{lbm}}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix}\begin{pmatrix}\frac{2000 \times 365}{3.413 \times 10^6}\\ \frac{\text{lbm - days - MWh}}{\text{ton - year - Btu}}\end{pmatrix} \quad \text{(A-12)}$$

$$\begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \text{Factor}\\ \$/\text{MWh/yr}\end{pmatrix} \times \left[\begin{pmatrix}\text{Electrical}\\ \text{Output}\\ \text{MWh/yr}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix}\right]^{\text{Exponent}} \quad \text{(A-13)}$$

$$+ \begin{pmatrix}\text{Turbine}\\ \text{Capital}\\ \text{Cost}\\ \$/\text{MW}\end{pmatrix} \times \left[\begin{pmatrix}\text{Plant}\\ \text{Capacity}\\ \text{MW}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix}\right]$$

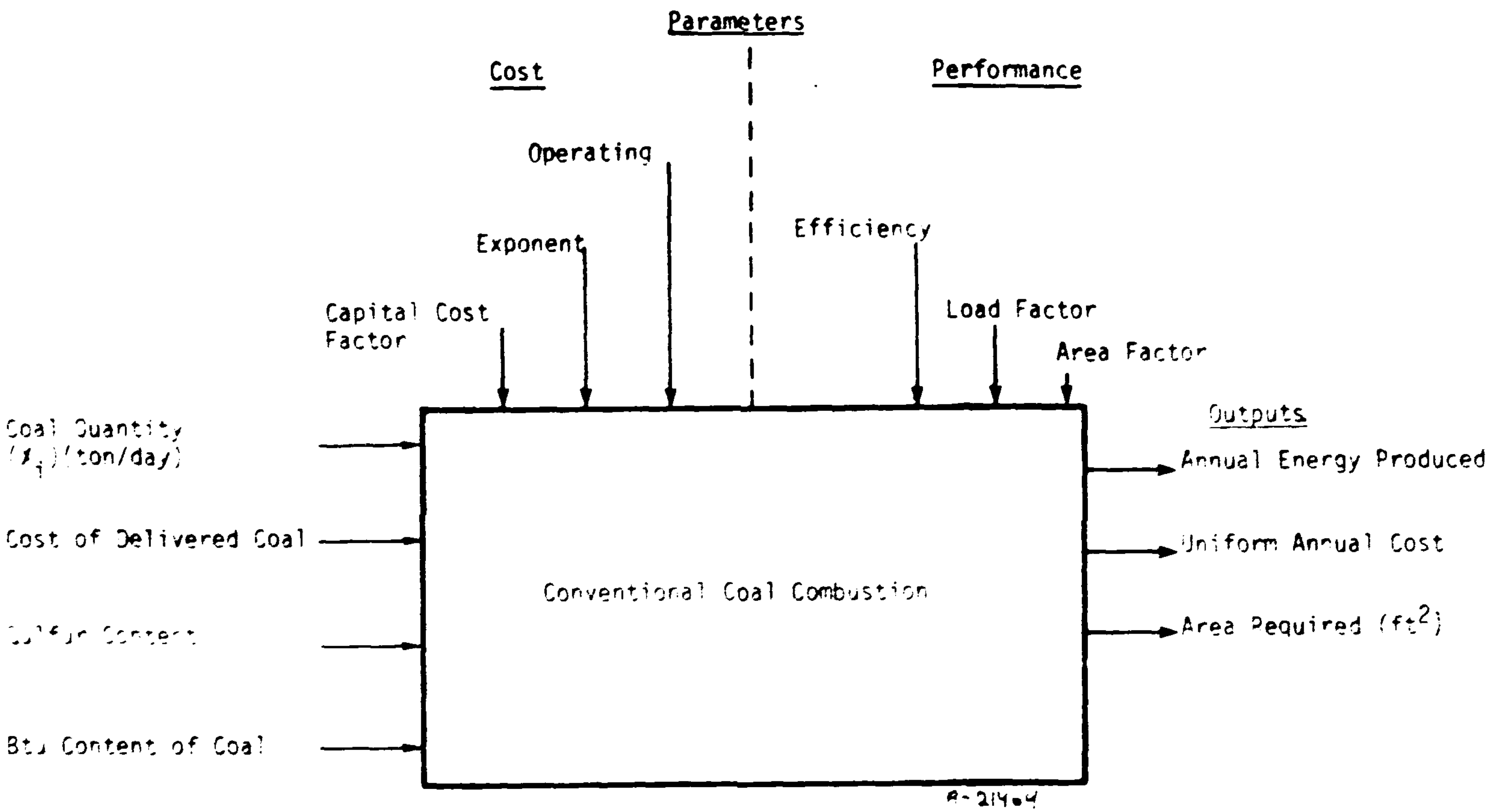

Figure A-10. Schematic of conventional coal combustion.

TABLE A-7. PERFORMANCE AND COST DATA -- CONVENTIONAL COAL ELECTRICITY MODEL

	Numerical Value	Comments	References
<u>Performance Data</u>			
Efficiency[a]	36%	Based upon a boiler efficiency of 85%. Efficiency varies from 33% to 39% depending upon size; an intermediate value was chosen.	A-17, A-20, A-21
Load Factor[b]	90%		
Area Factor	403 ft^2/(ton/day)	Assuming: (1) 60-day supply of coal stored as a conical pile with a 20° angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the coal pile.	A-6
<u>Cost Data</u>			
Capital Cost Factor			
Low Sulfur Coal	1.30×10^3 \$/(MWh/yr)	Capital cost includes cost for boiler, coal handling, ash handling, and pollution control equipment (see Section A.4.2.1).	A-9, A-22, A-23, A-24
High Sulfur Coal	1.21×10^3 \$/MWh/yr		
Exponent	0.75		A-25
Turbine Capital Cost	2.5×10^5 (\$/MW)	Condensing steam turbine	A-10
Operating Cost	50% Annualized Capital Cost	See Section 2.2.3	A-9, A-17, A-21

[a]Efficiency is defined as the ratio of electrical energy output to heating value of coal input.

[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

T-1884

TABLE A-8. PERFORMANCE AND COST DATA -- CONVENTIONAL COAL COAL STEAM MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency[a]	85%		A-21, A-26, A-27
Distribution Losses	10%	Heat loss from steam pipe distribution network	A-28
Load Factor[b]	90%		
Area Factor	403 ft^2/(ton/day)	Assuming: (1) 60-day supply of coal stored as a conical pile with a 20^o angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the coal pile.	A-6
Cost Data			
Capital Cost Factor			
Low Sulfur Coal	294 \$/(MBtu/yr)	Capital cost includes cost for boiler, coal handling, ash handling, and pollution control equipment (see Section A.4.2.1).	A-9, A-22 A-23, A-24
High Sulfur Coal	274 \$/(MBtu/yr)		
Exponent	0.75		A-25
Operating Cost	50% Annualized Capital Cost	See Section 2.2.3.	A-9, A-17, A-21

[a]Efficiency defined as the ratio of thermal value of steam output to the thermal value of coal input.
[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

$$\begin{pmatrix}\text{Maintenance}\\ \text{Cost}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Percent}\\ \text{Annualized}\\ \text{Capital}\\ \text{Cost}\end{pmatrix} \times \begin{pmatrix}\text{Annualized}\\ \text{Capital}\\ \text{Cost}\end{pmatrix} \qquad \text{(A-14)}$$

$$\begin{pmatrix}\text{Annual}\\ \text{Coal Cost}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Coal}\\ \text{Cost}\\ \$/\text{ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}365\\ \frac{\text{Days}}{\text{year}}\end{pmatrix} \qquad \text{(A-15)}$$

$$\begin{pmatrix}\text{Area}\\ \text{Required}\\ \text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\ \text{Factor}\\ \text{ft}^2/\\ \text{(Ton/Day)}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \qquad \text{(A-16)}$$

A.4.3 Fluidized Bed Combustion

This section describes the principles of fluidized bed combustion followed by a discussion of performance and cost factors used by the FBC computer subroutine.

A.4.3.1 Process Description -- FBC Production of Electricity and Steam

Fluidized bed combustion (FBC) involves burning 1 to 3 millimeter coal particles in a hot fluidized bed (750°C to 950°C) of inert solids, where the burning coal particles constitute only 2 weight percent of the total bed solids. The remaining portion consists of coal ash and limestone, or dolomite. Particles are fluidized by passing high velocity air upward through the bed of particles at rates which fully support the particle-bed weight (see Figure A-11). Rapid circulation of solid particles throughout the bed allows controlled isothermal combustion at extremely high heat transfer rates which reduces the required boiler size by one-half to two-thirds the size of a conventional boiler (Reference A-29). Sulfur is

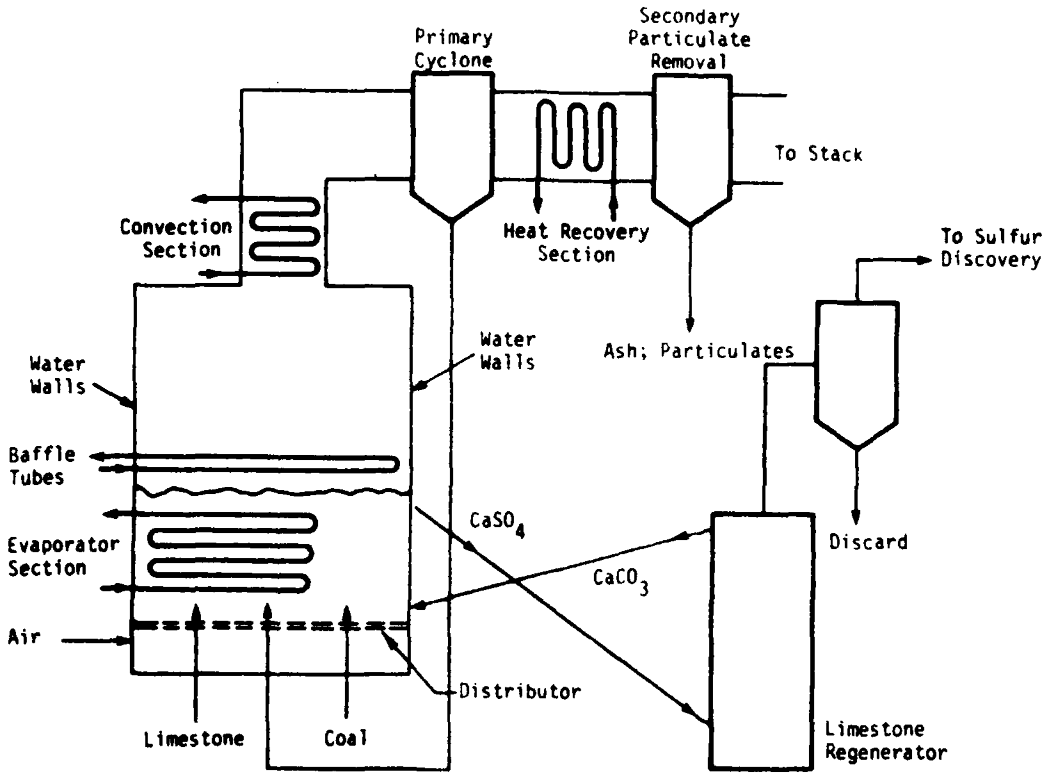

Figure A-11. Schematic of fluidized bed combustion system (Reference A-29).

removed from the coal by circulating limestone or dolomite through the fluidized bed.

There are two types of FBC systems: (1) atmospheric (AFBC) and (2) pressurized (PFBC). AFBC systems are designed to produce steam from tubes immersed directly in the fluidized bed. Steam can be used for process requirements or be passed through a turbine generator for conversion to electricity. PFBC systems (5 to 6 atmospheres) are designed to produce electricity using both a steam turbine-generator and a flue gas turbine-generator (80 percent electricity produced from steam, and 20 percent from flue gas). AFBC is a simpler system to develop and operate because of the lower pressures and lack of flue gas turbine required by a PFBC. Currently, AFBC systems are at the most advanced stage of development with cost and performance data available. Consequently, for this study we have modeled an atmospheric fluidized bed to meet space heating, process steam, and electrical demand.

A.4.3.2 Computer Model for FBC

The inputs, outputs, and parameters of the FBC computer subroutine are the same as those used by the conventional coal model given in Figure A-10. The specific equations used by the FBC electricity computer subroutine to calculate performance and cost are listed below.

Except for unit changes from MWh to MBtu the equations required to calculate performance and cost of the FBC coal steam model are identical to the FBC coal electricity model (less the turbine capital cost). It is assumed that the steam model can meet both the process steam and the space heating energy demand. Data input to the electricity and steam models are discussed in Tables A-9 and A-10, respectively.

TABLE A-9. PERFORMANCE AND COST DATA -- FBC ELECTRICITY MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency[a]	37%	Based on efficiency of existing atmospheric FBC. Efficiency of second generation systems may approach 45%.	A-30, A-31
Load Factor[b]	90%		
Area Factor	403 ft^2/(ton/day)	Assuming: (1) 60-day supply of coal stored as a conical pile with a 20^o angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the coal pile	A-6
Cost Data			
Capital Cost Factor	$\$3.61 \times 10^6$/MW	Although AFBC systems are projected to be commercial by 1980, capital cost data remain widely scattered.	A-7, A-25, A-30
Exponent	0.65	Fluidized bed combustion systems have significant economies of scale.	A-25
Operating Cost	50% annualized capital cost	See Section 2.2.3.	A-9

[a]Efficiency is defined as the ratio of electrical energy output to heating value of coal input.
[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

T-1887

TABLE A-10. PERFORMANCE AND COST DATA -- FBC STEAM MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency[a]	85%	Based on atmospheric FBC	A-30, A-31
Load Factor[b]	90%		
Area Factor	403 ft^2/(ton/day)	Assuming: (1) 60-day supply of coal stored as a conical pile with a 20^0 angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the coal pile	A-6
Cost Data			
Capital Cost Factor	$3,850/(MBtu/yr)	See Table A-9	A-9, A-25, A-30
Exponent	0.65	See Table A-9	A-25
Operating Cost	50% Annualized Capital Cost	See Section 2.2.3	A-9

[a]Efficiency is defined as the ratio of thermal value of steam output to the thermal value of coal input.
[b]Load factor is defined as the fraction of time a powerplant actually produces energy.

T-1888

Calculations

$$\begin{pmatrix}\text{Annual}\\\text{Electrical}\\\text{Output}\\\text{MWh/yr}\end{pmatrix} = \begin{pmatrix}\text{Quantity}\\\text{Coal}\\\text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}\text{Btu}\\\text{Content}\\\text{Coal}\\\frac{\text{Btu}}{\text{lbm}}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix}\begin{pmatrix}\frac{2000 \times 365}{3.413 \times 10^6}\\\frac{\text{lbm - days - MWh}}{\text{ton - year - Btu}}\end{pmatrix} \quad \text{(A-17)}$$

$$\begin{pmatrix}\text{Capital}\\\text{Cost}\\\$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\\text{Cost}\\\text{Factor}\\\text{\$/MWH/yr}\end{pmatrix} \times \left[\begin{pmatrix}\text{Electrical}\\\text{Output}\\\text{MWH/hr}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\\text{Factor}\end{pmatrix}\right]^{\text{Exponent}} \quad \text{(A-18)}$$

$$+ \begin{pmatrix}\text{Turbine}\\\text{Capital}\\\text{Cost}\\\text{\$/MW}\end{pmatrix} \times \left[\begin{pmatrix}\text{Plant}\\\text{Capacity}\\\text{MW}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\\text{Factor}\end{pmatrix}\right]$$

$$\begin{pmatrix}\text{Maintenance}\\\text{Cost}\\\text{\$/yr}\end{pmatrix} = \begin{pmatrix}\text{Percent}\\\text{Annualized}\\\text{Capital}\\\text{Cost}\end{pmatrix} \times \begin{pmatrix}\text{Annualized}\\\text{Capital}\\\text{Cost}\end{pmatrix} \quad \text{(A-19)}$$

$$\begin{pmatrix}\text{Annual}\\\text{Coal Cost}\\\text{\$/yr}\end{pmatrix} = \begin{pmatrix}\text{Coal}\\\text{Cost}\\\text{\$/ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\\text{Coal}\\\text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}365\\\frac{\text{Days}}{\text{year}}\end{pmatrix} \quad \text{(A-20)}$$

$$\begin{pmatrix}\text{Area}\\\text{Required}\\\text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\\text{Factor}\\\text{ft}^2/\\\text{(Ton/Day)}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\\text{Coal}\\\text{Ton/Day}\end{pmatrix} \quad \text{(A-21)}$$

A.5 SOLAR ENERGY

A.5.1 Introduction

It is estimated that the amount of solar energy incident on the continental United States each year is 700 times our annual rate of energy consumption (Reference A-32). This represents a substantial source of energy. In the past, solar energy has been regarded as economically unfeasible because of the large capital investment required compared to the amount of energy produced. But with increasing conventional fuel prices, active government support of solar energy development programs and potential reduction of solar equipment costs due to mass production, solar energy is projected to be competitive between 1980 and 1990.

Space heating and domestic hot water account for 10 to 20 percent of all energy consumed on Navy bases. It has been demonstrated that solar energy systems using flat-plate or concentrating collectors are technically capable of meeting this demand, and they are economically competitive. Consequently, this study has modeled solar thermal systems to meet heating demands. This model is discussed in detail in Section A.5.2.

The Battelle Columbus Laboratories (Reference A-33) reported that 35 percent of all industrial demand for process heat falls into the temperature range below 180°C, which is clearly within the capability of solar energy systems using concentrating collectors. Although solar steam systems are a viable alternate energy system, they were not modeled for this effort.

Solar energy systems can produce electricity using either rankine cycles or photovoltaic cells. Solar rankine cycles are presently in the experimental stage of development. Consequently, adequate commercial

scale models are not available. In contrast, as a result of the aerospace program, photovolatic systems are a proven technology and are commercially available. In addition, the application of electronic, silicon technology to photovoltaic development will assure rapid reduction of photovoltaic cell cost as projected by the Department of Energy. This study has modeled solar photovoltaic systems to meet electrical demand. This model is discussed in detail in Section A.5.3.

A.5.2 Process Description for Solar Thermal

Solar energy can be converted to thermal energy and used to supply hot water, space heating, and/or space cooling to commerical or residential buildings. This study will model liquid solar thermal systems to meet only space heating and hot water demand, not space cooling which will be considered an electrical demand for this study. An active solar system consists primarily of a collector, a distribution system, and a storage system. Thus, heat absorbed by the working fluid in the collector is pumped through heat exchangers to deliver space heating or hot water, and pumped into a liquid tank to store thermal energy (refer to Figure A-12). Water, glycol and water mixtures, and hydrocarbon oils are typical working fluids.

Collectors are typically installed on roof tops. But, if adequate area is not available on the roof, land adjacent to the buildings can also be used. Collector designs range from a simple single glazed nonconcentrating flat-plate collector, to the more sophisticated line-focusing parabolic trough concentrating collector (see Figure A-13). This study will model flat-plate collectors to supply energy for heating demand. For a flat-plate collector, solar radiation is absorbed by a black metal plate, and converted to thermal energy. This thermal energy

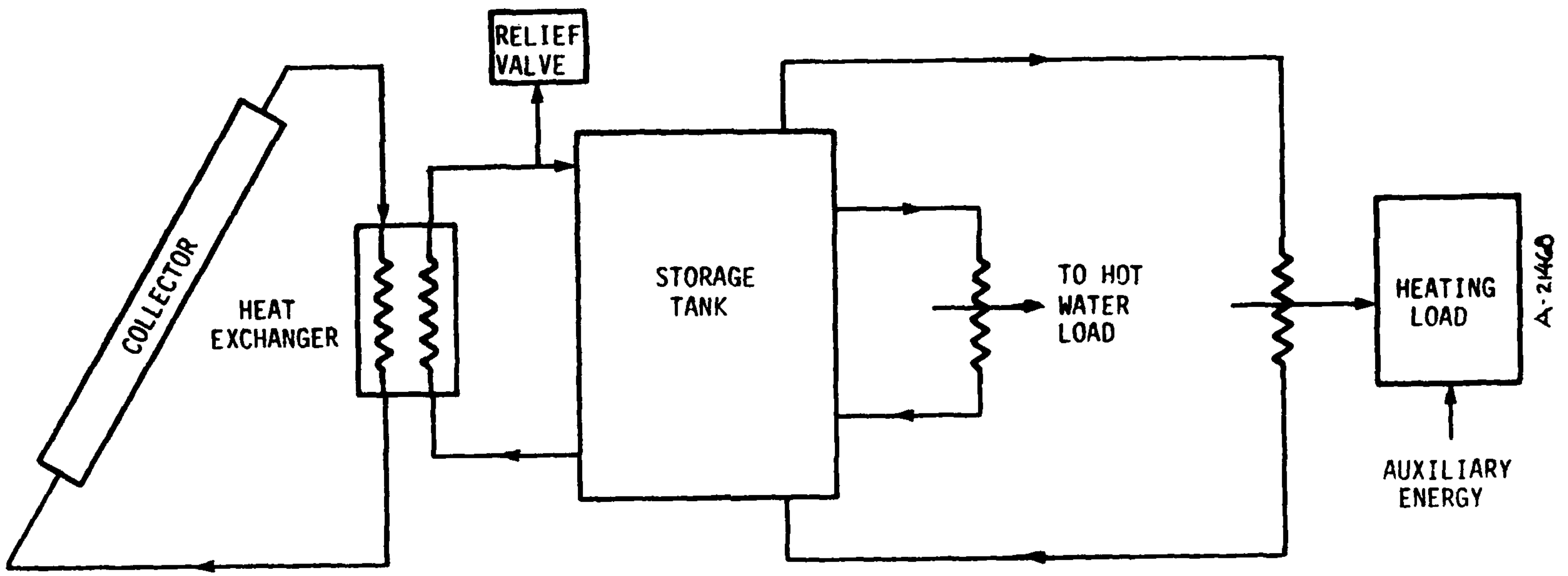

Figure A-12. Space heating (and domestic hot water) system.

Figure A-13. Acurex Model 3001 concentrating collector.

BLANK PAGE

is removed by working fluids which circulate through metal tubes bonded to the metal plate. The black metal plate and tube sheet are covered by a glass or plastic window to reduce heat losses through the back and sides (Figure A-14). Flat-plate collectors achieve working fluid temperatures less than 200^{o}F.

Optimum solar systems should be capable of storing energy in the form of sensible heat for 1 to 2 days. Thus, excess energy produced during periods of high insolation and low demand must be stored and later delivered to satisfy heating demands during periods of low insolation (during the night and cloudy days) and high demand. Unfortunately, the present computer optimization code cannot transfer excess thermal energy to a later time. However, an empirical correlation (f-chart) developed by Klein does account for storage capability (Reference A-34). The f-chart method requires only average monthly insolation and average monthly heating load to determine the fraction of that load which can be met by solar energy systems. The solar heating computer subroutine uses this method to determine system performance.

An outline of the method is presented below.

Basis of method:

- Simplified collection system with storage (Figure A-12)
- State-of-the-art selection of components
- Correlation of over 300 computer simulations

Input requirements:

- Net collector aperature
- Collector efficiency curve
- Total monthly insolation incident on collectors

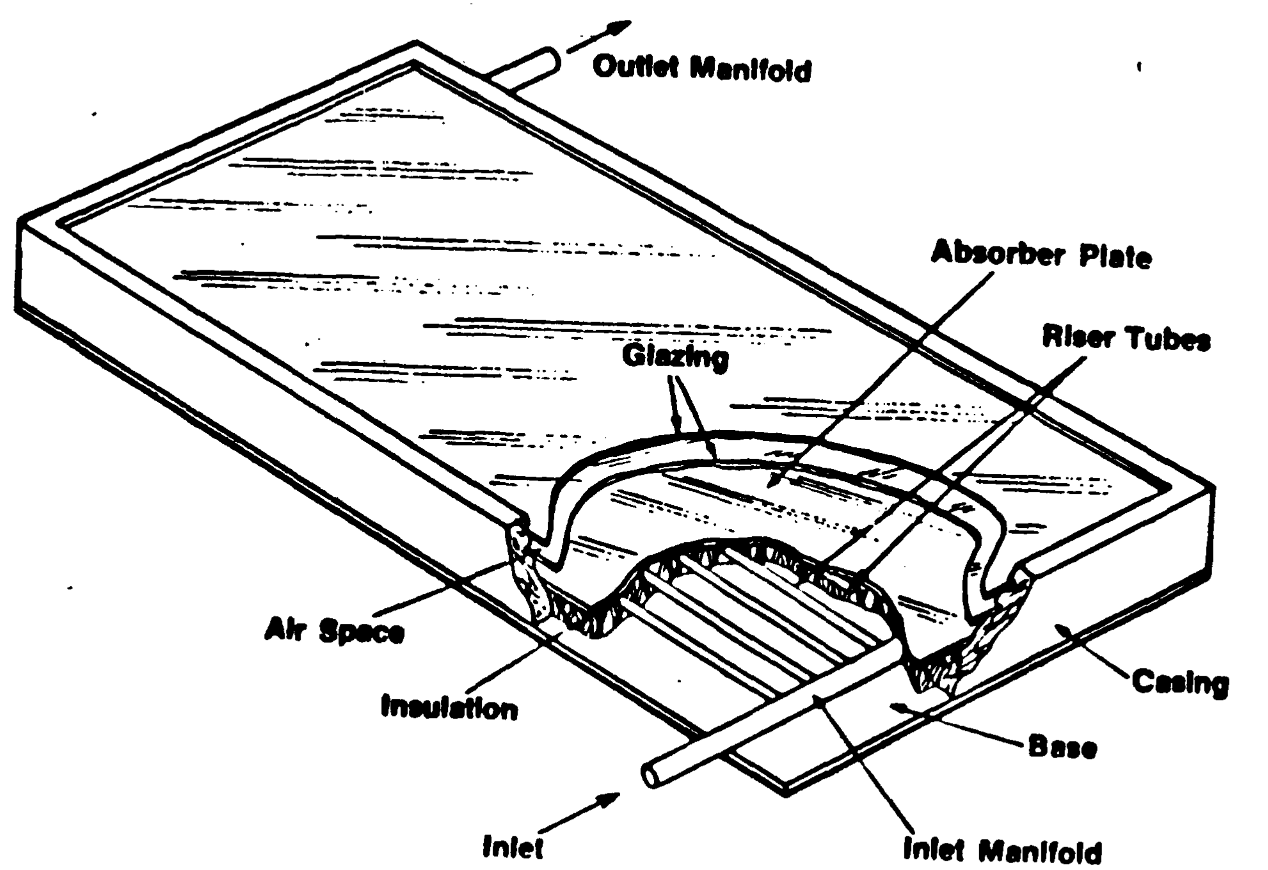

Figure A-14. Typical construction of a "sheet and tube" flat-plate collector.

- Monthly average ambient temperature
- Total monthly hot-water and space-heating load

Results:

- Fraction of total monthly load which is satisfied by solar system

A.5.2.1 Computer Model for Solar Thermal

Figure A-15 presents a schematic diagram of the inputs, outputs, and parameters of the solar thermal subroutine.

The performance equations and parameters for the solar thermal model are contained in the f-chart correlation described below. Data input to the solar thermal model are discussed in Table A-11.

Calculations

$$\begin{pmatrix}\text{Annual}\\ \text{Energy Output}\\ \text{Btu/yr}\end{pmatrix} = \sum_{i=1}^{12} \begin{pmatrix}\text{Month Space Heating}\\ \text{and Hot Water}\\ \text{Demand Btu/month}\end{pmatrix}_i \times \underbrace{\begin{pmatrix}\text{Fraction Monthly}\\ \text{Heating Demand}\\ \text{met by Solar}\end{pmatrix}_i}_{F_s} \qquad \text{(A-22)}$$

where:

$$F_S = 1.029\ P_s - 0.065P_L - 0.245P_s^2 + 0.0018P_L^2$$

If $F_s > 1.0$, then $F_s = 1.0$

and:

$$P_L = \left[(F_R'\ U_L\ A_{coll}(T_R - \bar{T}_a)\ \ \Delta t\right] /L$$

$$P_s = \left[(F_R'\ \tau\alpha)\ A_{coll} I_{coll}\right] /L$$

Defined as:

$F_R'U_L$ = collector loop heat-exchanger factor times collector heat loss coefficient, (Btu/hr-ft^2-^{o}F).

$F_p'\tau\alpha$ = collector loop heat-exchanger factor times monthly average collector transmittance-absorptance product.

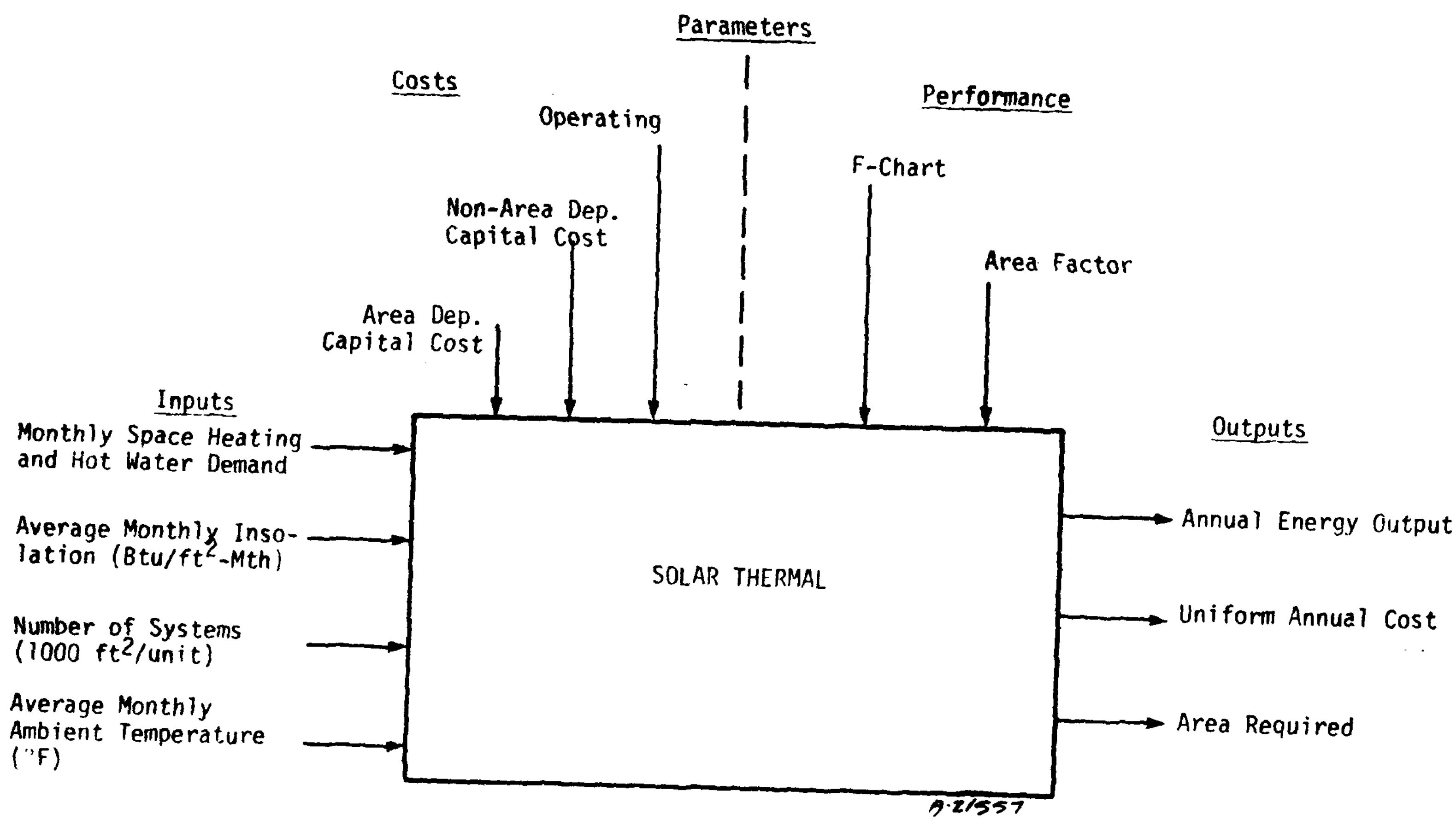

Figure A-15. Schematic diagram for solar thermal model.

TABLE A-11. PERFORMANCE AND COST DATA -- SOLAR THERMAL MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency	Variable	Performance determined by f-chart method (see previous discussion Section A.5.2.1)	A-34
Area Factor	$\frac{2.5\ ft^2}{1\ ft^2\ collector}$	Additional space required to prevent shading by adjacent collector panels	
Cost Data			
Area Dependent[a] Capital Cost Factor	$35/ft^2 collector	Cost includes piping, storage units, collector panels, and installation	A-35, A-9, A-36, A-37
Non-Area Dependent Capital Cost Factor	$85,000/system	Cost includes controls, heat exchangers, and auxiliary power	A-35, A-9, A-36, A-37
Exponent	1.0	No economies scale	
Annual Operating Cost	20% Uniform Annual Cost	Periodic cleaning of solar collectors, general maintenance	A-35, A-10

[a]Costs of solar systems vary widely depending upon the particular collector design, temperature requirements, and location (roof versus ground).

T-1891

$$A_{coll} = \begin{pmatrix} \text{Area} \\ \text{Collector} \\ \text{ft}^2 \end{pmatrix} = \begin{pmatrix} \text{Number} \\ \text{of} \\ \text{Systems} \end{pmatrix} \times \begin{pmatrix} 1000 \\ \text{ft}^2/\text{system} \end{pmatrix} \qquad \text{(A-23)}$$

T_R = 212°F

$\overline{T}a$ = Average monthly ambient temperature, °F

Δt = Number of hours per month, hr/month

L = Total monthly space heating and hot water load, Btu/month

I_{coll} = Average total monthly collector plane insolation, Btu/month °F

$$\begin{pmatrix} \text{Capital} \\ \text{Cost} \\ \$ \end{pmatrix} = \begin{pmatrix} \text{Number} \\ \text{of} \\ \text{Systems} \end{pmatrix} \times \begin{pmatrix} \text{Area} \\ \text{Dependent} \\ \text{Cost \$/ft}^2 \end{pmatrix} \times \begin{pmatrix} 10{,}000 \\ \text{ft}^2/\text{system} \end{pmatrix} + \begin{pmatrix} \text{Nonarea} \\ \text{Dependent} \\ \text{Cost \$} \end{pmatrix} \qquad \text{(A-24)}$$

$$\begin{pmatrix} \text{Operating} \\ \text{Cost} \\ \text{\$/yr} \end{pmatrix} = \begin{pmatrix} \% \\ \text{Annualized} \\ \text{Capital Cost} \end{pmatrix} \times \begin{pmatrix} \text{Annualized} \\ \text{Capital} \\ \text{Cost} \end{pmatrix} \qquad \text{(A-25)}$$

$$\begin{pmatrix} \text{Area} \\ \text{Required} \\ \text{ft}^2 \end{pmatrix} = \begin{pmatrix} \text{Number} \\ \text{of} \\ \text{Systems} \end{pmatrix} \times \begin{pmatrix} \text{Area} \\ \text{Factor} \\ \text{ft}^2/\text{system} \end{pmatrix} \qquad \text{(A-26)}$$

A.5.3 Process Description for Solar Photovoltaic

A photovoltaic energy system consists of an array of photovoltaic cells which directly convert solar radiation into electrical power. This current is passed through inverters which convert photovoltaic D.C. current to the desired A.C. current. Presently, manufactured photovoltaic cells consist primarily of a single crystal silicon base doped with boron and phosphorous impurities. This doping produces a charge potential capable of converting visible light into electric current at efficiencies of approximately 10 percent.

Advanced cells, capable of higher efficiencies, are being constructed with gallium arsenide and cadmium sulfide. Cell efficiency decreases with increasing temperature, consequently, cells are cooled with circulating water to maintain the cells at peak efficiency. Although this represents a potential source of thermal energy, it is currently neglected.

Because of the high cost and low efficiency of batteries, electrical storage is not presently economical, and was not considered in this study. (However, breakthroughs in electrical storage devices may reverse this situation.) Consequently, performance of photovoltaic cells will depend directly on the accuracy of daily insolation profiles (i.e., average monthly values cannot be used directly). Section 4.2 discusses the approach taken to generate daily insolation profiles from monthly average insolation values.

Both concentrating and nonconcentrating (flat-plate) arrays can be used to generate electricity. Analogous to solar thermal systems, concentrating photovoltaic systems utilize fresnel lens (methyl methacrylate), paraboloid reflectors, or disk reflectors to focus solar radiation on the photovoltaic cells, thus requiring fewer cells for the same electrical output. As a result, installed concentrating photovoltaic systems cost approximately $2,200/peak kW, whereas nonconcentrating systems cost approximately $17,400/peak kW (Reference A-37).

Because concentrating systems are cheaper than nonconcentrating systems, this study models a water-cooled concentrating (paraboloid reflector) photovoltaic system, located on the ground, which produces electricity without electrical storage capability (Figure A-16).

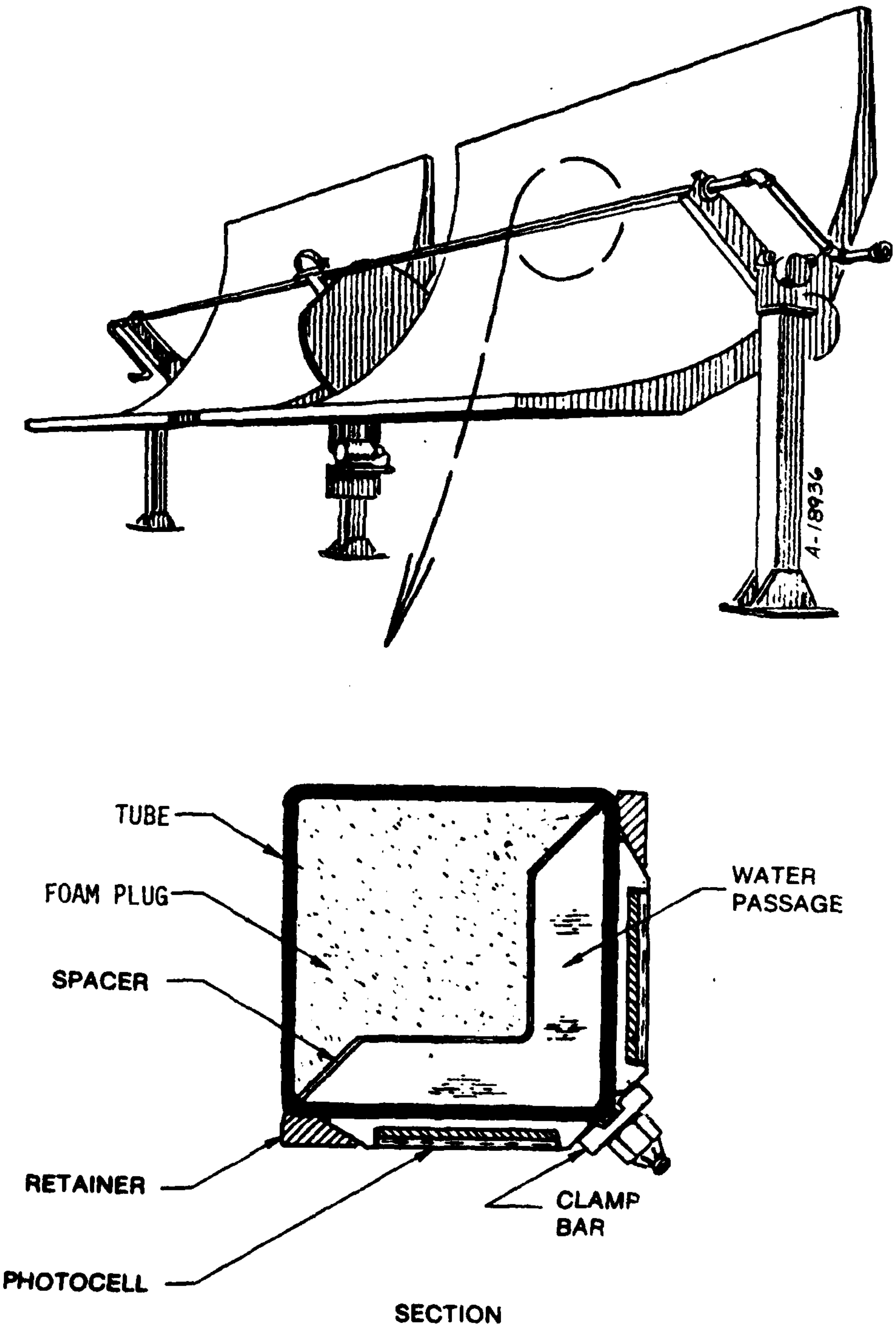

Figure A-16. Concentrating photovoltaic collector.

A.5.3.1 Computer Model for Solar-Photovoltaic

Figure A-17 presents a schematic diagram of the inputs, outputs, and parameters of the solar photovoltaic computer subroutine. The equations used by the solar photovoltaic computer subroutine to calculate performance and cost are listed below. Data input to the model are discussed in Table A-12.

Calculations

$$\begin{pmatrix}\text{Annual}\\\text{Energy}\\\text{Output}\\\text{MWH/yr}\end{pmatrix} = \sum_{j=1}^{12} \text{Day}_j \left[\sum_{i=1}^{24} \begin{pmatrix}\text{Hourly}\\\text{Insolation}\\\text{MWH/}\\\text{ft}^2\text{-hr}\end{pmatrix}_i \times \begin{pmatrix}\text{Number}\\\text{of}\\\text{Systems}\end{pmatrix} \times \begin{pmatrix}1000\\\text{ft}^2/\\\text{system}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix}\right] \tag{A-27}$$

where Day_j = Number of days in month_j

i = hour i

$$\begin{pmatrix}\text{Capital}\\\text{Cost}\\\$\end{pmatrix} = \begin{pmatrix}\text{Number}\\\text{of}\\\text{Systems}\end{pmatrix} \times \begin{pmatrix}\text{Area}\\\text{Dependent}\\\text{Cost}\\\$/\text{ft}^2\end{pmatrix} \times \begin{pmatrix}1000\\\text{ft}^2/\\\text{system}\end{pmatrix} \tag{A-28}$$

$$\begin{pmatrix}\text{Operating}\\\text{Cost}\\\$/\text{yr}\end{pmatrix} = \begin{pmatrix}\%\\\text{Annualized}\\\text{Capital}\\\text{Cost}\end{pmatrix} \times \begin{pmatrix}\text{Annualized}\\\text{Capital}\\\text{Cost}\end{pmatrix} \tag{A-29}$$

$$\begin{pmatrix}\text{Area}\\\text{Required}\\\text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Number}\\\text{of}\\\text{Systems}\end{pmatrix} \times \begin{pmatrix}\text{Area}\\\text{Factor}\\\text{ft}^2/\\\text{system}\end{pmatrix} \tag{A-30}$$

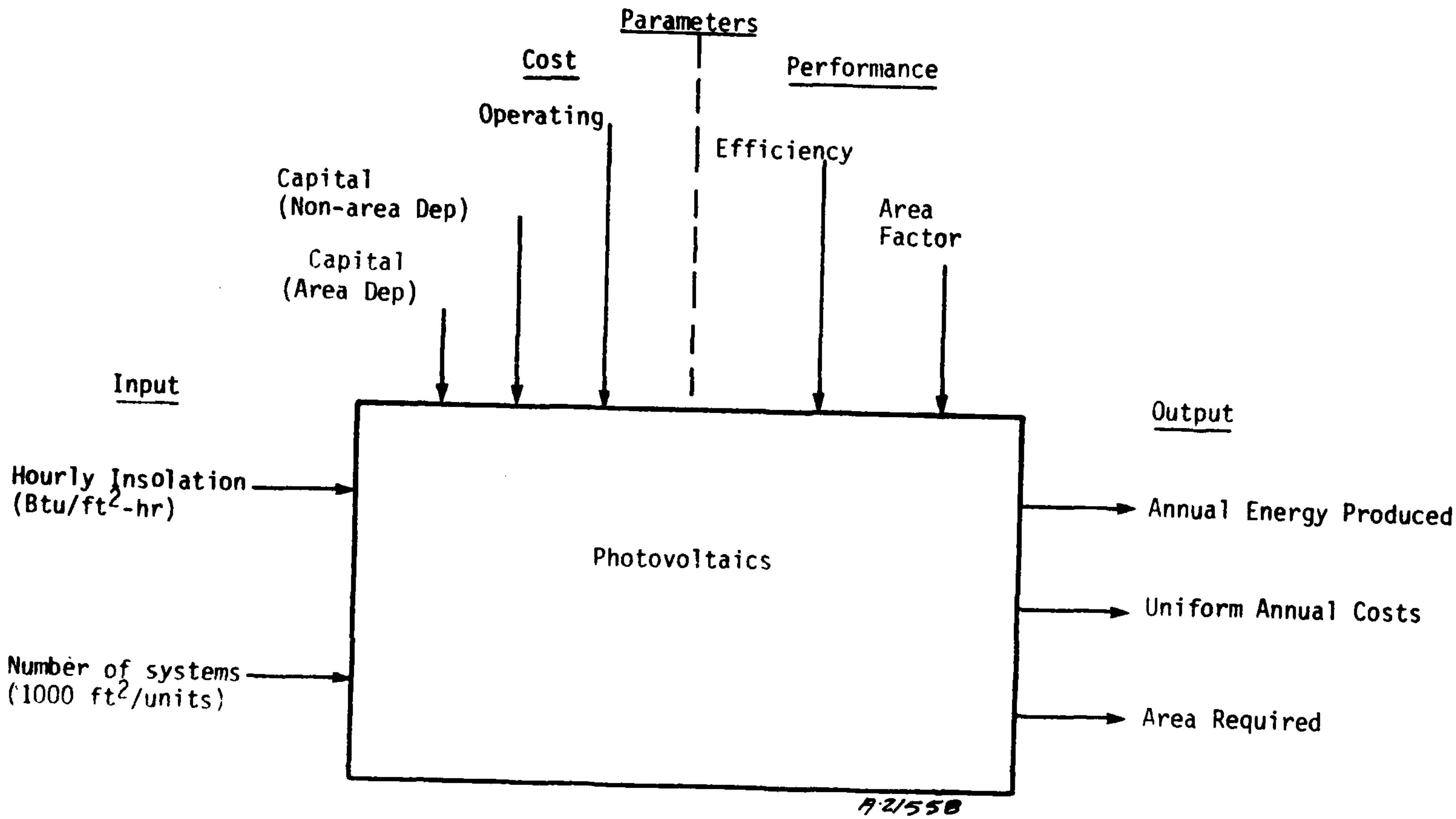

Figure A-17. Schematic diagram for solar photovoltaic model.

TABLE A-12. PERFORMANCE AND COST DATA -- SOLAR PHOTOVOLTAIC MODEL

	Numerical Value	Comments	References
Performance Data			
Efficiency[a]	10%	Advanced photovoltaic cells may achieve efficiencies of 20%	A-38, A-39, A-40
Area Factor	$\frac{2.5\ ft^2}{ft^2\ collector}$	Additional space required to prevent shading by adjacent collector panels	
Cost Data			
Capital Cost Factor	$\frac{\$32.00}{ft^2\ collector}$	For a concentrating parabolic collector, cost includes support structure, photovoltaic cells, wiring, control systems, and installation	A-39, A-40
Exponent	1.0	No economies of scale	
Annual Operating Cost	20% Uniform Annual Cost	Periodic cleaning of photovoltaic cells, general maintenance	A-35, A-10

[a]*Efficiency defined as the ratio of electrical output of solar radiation input.*

T-1890

A.6 WIND ENERGY

A.6.1 Introduction

Wind has been used as an energy source by man for several thousand years. During the period from 1900 to 1955, windpowered electric generating systems were widely used in rural areas of the United States. But, with the introduction of low cost hydroelectric power and distribution to rural areas, most wind generators were abandoned by 1955.

Windpower is a function of wind velocity cubed. Consequently, energy costs decrease rapidly with increased average windspeed. For example, wind produced electric energy cost may range from 150 to 200 mills/kWh at 9.4 mph average windspeed, whereas these costs may be as low as 50 mills/kWh at 15 mph average windspeed (Reference A-41). Studies suggest that sites with average windspeeds in excess of 15 mph may be required to economically support wind generator systems (Reference A-42).

Diurnal variations in windspeed, at most locations, peak in the afternoon and drop significantly during the night. Therefore, although windpower is pollution free and uses a renewable energy source, it produces power only when the wind blows, not necessarily when energy is needed. In addition, due to the high capital cost and inefficiency of electric storage batteries, it is not economical to store electric energy. Therefore, wind generators are modeled to produce electricity without electrical storage.

This study has modeled three types of wind-electric generators; 5 kW, 200 kW, and 1500 kW units. These models are discussed in detail in Section A.6.3.

A.6.2 Process Description for Wind-Electric Model

Wind driven generator systems consist of three primary components as illustrated in Figure A-18. These are:

1. Turbine -- Wind turbines, classified as horizontal, vertical, and confined vortex, convert wind kinetic energy into rotary motion. This study has selected the rotor turbine design (as portrayed in Figure A-18) because it is a simple, technically proven technology.
2. Tower -- The tower consists of the support for the rotor which contains the generator and electronic control system.
3. Inverter -- The inverter converts the direct current wind generator output into alternating current analogous to utility supplied electric power.

Accurate evaluation of the performance and cost of wind-electric systems depends significantly upon accurate simulation of annual, as well as daily, wind velocity profiles. Refer to Section 4.2 for a detailed discussion.

A.6.3 Computer Model for Wind-Electric Systems

Figure A-19 presents a schematic diagram of the inputs, outputs, and parameters of the wind-electric computer subroutine.

Because performance of wind-electric models is not constant but varies with wind velocity, performance data is contained within the computer subroutine, not inputted as parameters to the model. The equations used by the wind-electric model computer subroutines to calculate performance and cost are listed below. Data input to the model are discussed in Table A-13.

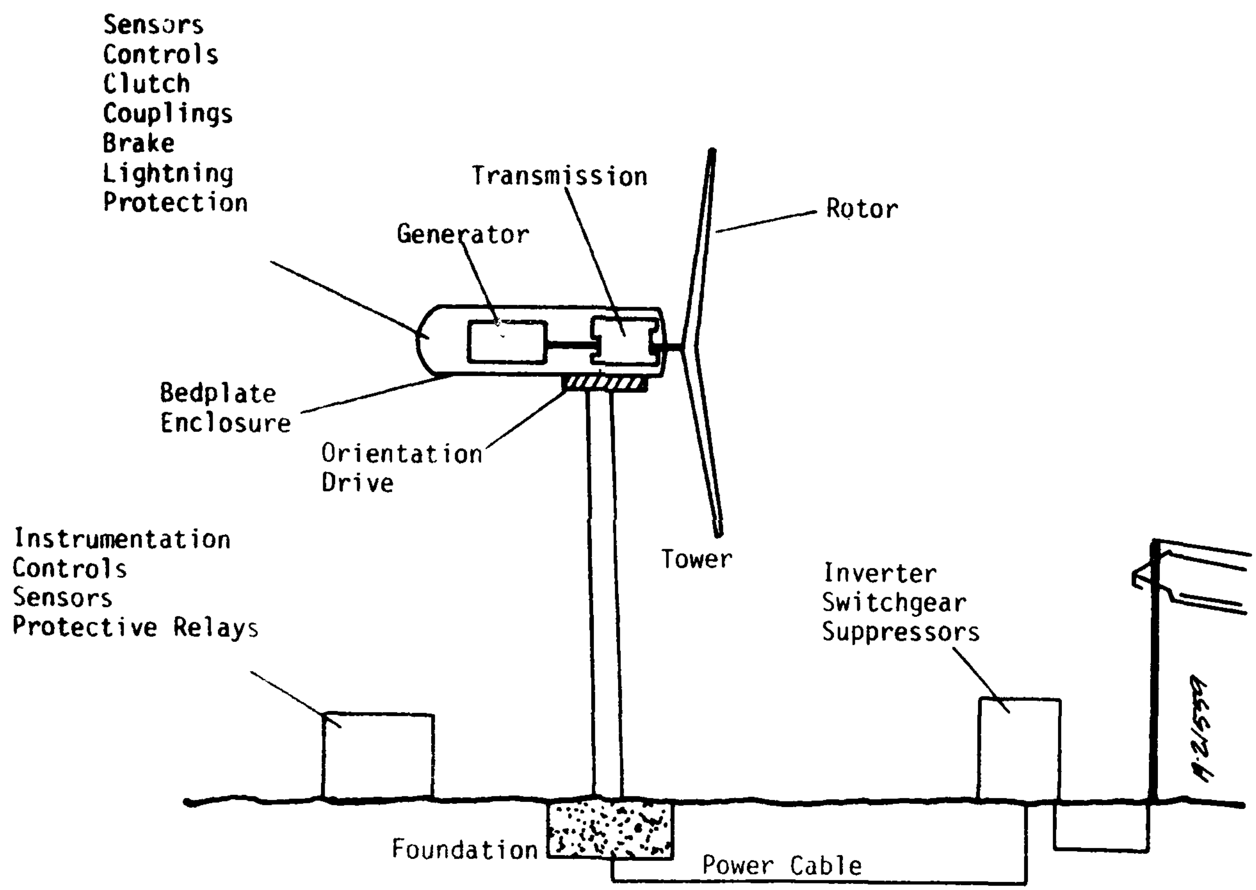

Figure A-18. Wind-electric system.

AD-A081 383 ACRUEX CORP MOUNTAIN VIEW CA ENERGY AND ENVIRONMENTAL DIV F/G 10/3
APPLICATION POTENTIAL OF ENERGY SYSTEMS AT NAVY SITES. VOLUME I--ETC(U)
JAN 80 S J ANDERSON, M D JACKSON, S J CHAMP N68305-78-C-0009

UNCLASSIFIED CEL-CR-80.006-VOL-1 NL

3 OF 3

AD
A081383

END
DATE
FILMED
4-80
DTIC

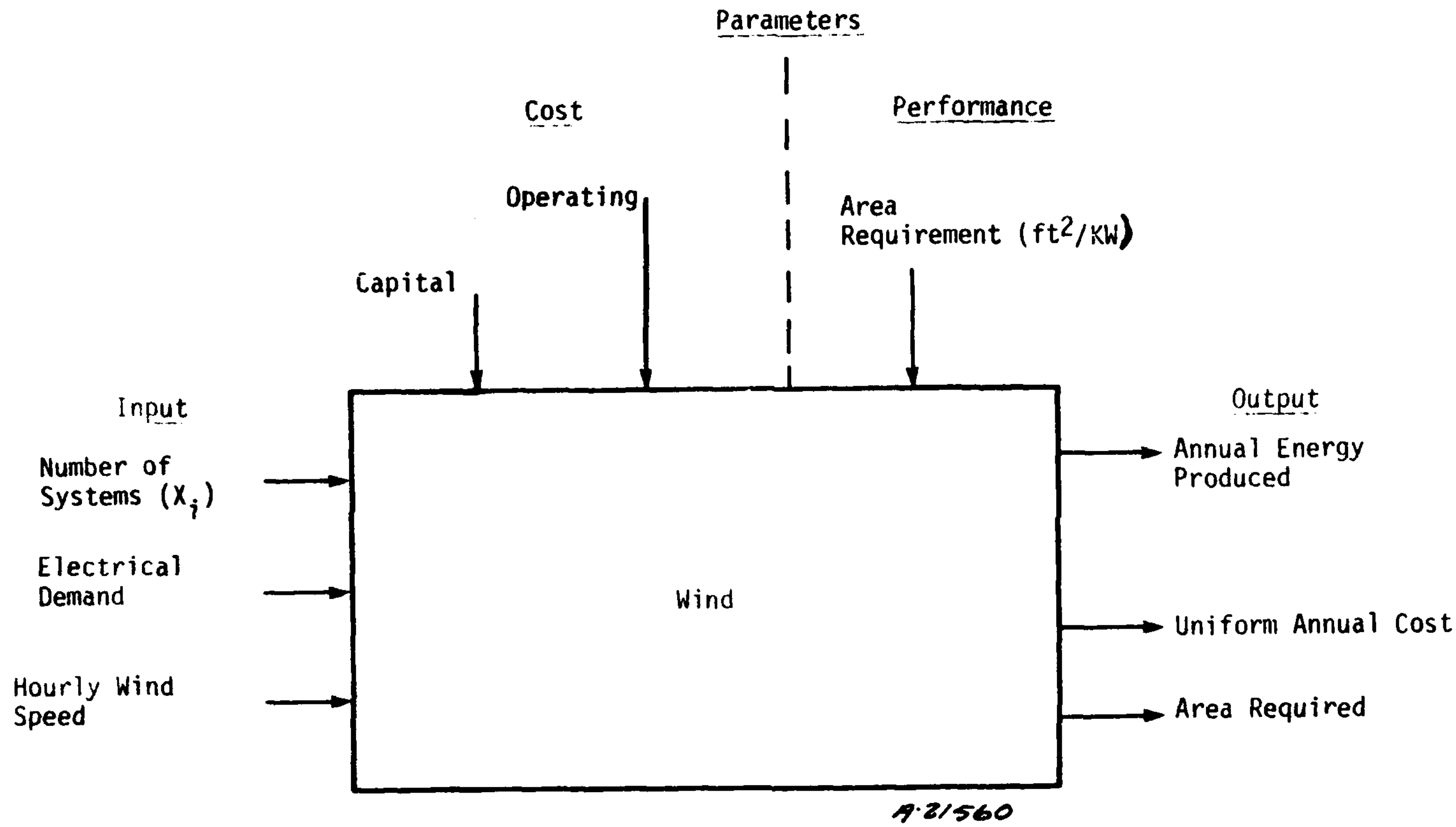

Figure A-19. Schematic diagram for wind model.

TABLE A-13. PERFORMANCE AND COST DATA -- WIND GENERATOR MODELS

	Numerical Value	Comments	References
Performance Data			
Efficiency			
-- 5 kW	Variable	Electrical power produced is a function of velocity cubed (see previous discussion, Section A.6.3.)	A-38
-- 200 kW	Variable	Wind power is a linear function of velocity within threshold velocity limits.	A-38
-- 1500 kW	Variable	See comment, 200 kW system efficiency	A-38
Area Factor			
-- 5 kW	300 ft^2/unit	Area required for rotor clearance	A-15
-- 200 kW	16,000 ft^2/unit	Same as above	A-15
-- 1500 kW	33,000 ft^2/unit	Same as above	A-15
Cost Data			
Capital Cost Factor		Cost includes rotor, tower, foundation, generator, transformer, and control system	A-15, A-43
-- 5 kW	$15,000/unit		A-15, A-43
-- 200 kW	$500,000/unit		A-15, A-43
--1500 kW	$1,500,000/unit		A-15, A-43
Operating Cost		Includes general maintenance	
-- 5 kW	$375/unit-yr		A-15, A-44
-- 200 kW	$15,000/unit-yr		A-15, A-44
-- 1500 kW	$112,500/unit-yr		A-15, A-44

T-1886

Calculations

$$\begin{pmatrix}\text{Annual}\\\text{Energy}\\\text{Output}\\\text{MWH/yr}\end{pmatrix} = \sum_{j=1}^{12} (\text{Day}_j) \times \left[\sum_{i=1}^{24} (K)\right] \tag{A-31}$$

where

Day_j = Number of days in month;

For a 5-kW wind generator:

$$K = (0.795 \times 10^{-6}) \cdot (C_p) \cdot (V_i)^3$$

where

$$C_p = \begin{cases} 0 & v \le 7 \\ .510 - .007v; & 7 \le v \le 23 \\ .710 - .015v; & 23 < v \le 45 \\ 0 & v > 45 \end{cases}$$

For a 200 kW wind generator:

$$K = \begin{cases} 0 & v < 8 \\ -.1064 + .0133v; & 8 \le v \le 18 \\ 0.133 & 18 < v \le 60 \\ 0 & v > 60 \end{cases}$$

For a 1500 kW wind generator:

$$K = \begin{cases} 0 & v < 12 \\ .1154v - 1.385; & 12 \le v \le 25 \\ 1.500 & 25 < v \le 45 \\ 0 & v > 45 \end{cases}$$

where v_i = wind velocity at hour i (mph)

k = (MWh)

(Reference A-38) (A-32)

$$\begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \$\end{pmatrix} = \begin{pmatrix}\text{Number}\\ \text{of}\\ \text{Systems}\end{pmatrix} \times \begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \text{Factor}\\ \$/\text{system}\end{pmatrix} \tag{A-33}$$

$$\begin{pmatrix}\text{Operating}\\ \text{Cost}\\ \$/\text{yr}\end{pmatrix} = \begin{pmatrix}\text{Number}\\ \text{of}\\ \text{Systems}\end{pmatrix} \times \begin{pmatrix}\text{Operating}\\ \text{Cost Factor}\\ \$/\text{system-yr}\end{pmatrix} \tag{A-34}$$

$$\begin{pmatrix}\text{Area}\\ \text{Required}\\ \text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Number}\\ \text{of}\\ \text{Systems}\end{pmatrix} \times \begin{pmatrix}\text{Area}\\ \text{Factor}\\ \text{ft}^2/\text{system}\end{pmatrix} \tag{A-35}$$

A.7 COGENERATION

A.7.1 Introduction

Cogeneration and combined cycles are terms used interchangeably to describe the simultaneous production of both electricity and useful heat or process steam. In a steam-topping cycle for example, high pressure steam is passed initially through a turbine to produce electricity, then exhausted at a lower pressure for process applications. In this manner, exhaust steam is considered a credit rather than a waste as in the case for utility powerplants.

Cogeneration is not a new, innovative technology. In West Germany, 29 percent of the total electric power is produced by industry. In 1950, 15 percent of the U.S. electrical demand was met by in-plant electric power generation. However, due to inexpensive, readily available commercial electricity, this fraction has declined to 5 percent in 1973 (Reference A-23). In effect, industry chose to invest in alternatives with higher returns on investment. But, the increase in petroleum prices following the Arab embargo with subsequent increase in electricity cost, substantially improved investment opportunity for industrial cogeneration systems.

The potential of cogeneration is substantial. Presently, 45 percent or 13×10^{15} Btu/year is consumed by U.S. industry for steam generation. Using steam-topping cogeneration systems, a significant portion of this steam could also be used to produce electricity. The actual market penetration depends upon the steam and electric demand fluctuations, the magnitude of the demands, type of financing, and industrial-utility interface.

Three basic types of cogeneration systems are commercially available: (1) gas turbines (Brayton cycle), (2) diesel engines, and (3) back-pressure steam turbine (Rankine cycle). In gas turbine systems, combustion of light distillate fuel or natural gas yields a hot, pressurized gas that can directly drive a gas turbine-generator, producing electricity. Hot exhaust gases from the gas turbine pass over water-filled tubes in a waste heat boiler, producing process steam.

Utilizing a conventional cylinder-piston mechanism, diesel engines produce mechanical power capable of driving an electric generator.

Similar to a gas turbine, heat in the exhaust gas from the engine cylinders is recovered to generate process steam.

Both gas turbines and diesel engines produce primarily electricity and only small quantities of low pressure steam. In contrast, back pressure steam turbines produce primarily steam. For back pressure steam turbine systems, high pressure steam generated from a boiler passes through a noncondensing turbine-generator producing electricity. Exhaust steam from the turbine is used subsequently for industrial applications.

The Navy generates large quantities of steam for industrial as well as domestic and commercial space heating requirements. This substantial steam demand in combination with an electrical demand allows a steam-topping cogeneration system to be a viable alternative energy source for the Navy. A coal-fired steam-topping cycle is a proven, highly reliable technology which does not rely on restricted supplies of oil and natural gas. Consequently, this study chose to model a coal-fired steam-topping cogeneration system.

A.7.2 Process Description

As an overview, steam produced by a boiler is passed through a turbine to generate electricity. Exhaust steam from the turbine can be used either for space heating or industrial process applications. In this manner, electricity and process steam are produced simultaneously. Figure A-20 illustrates a steam-topping cogeneration system.

A steam-topping cycle consists of four primary components: (1) coal-fired stoker boiler, (2) fuel and ash handling equipment, (3) pollution control equipment, and (4) a turbine-generator. Except for the turbine, the components of a steam cogeneration system are identical

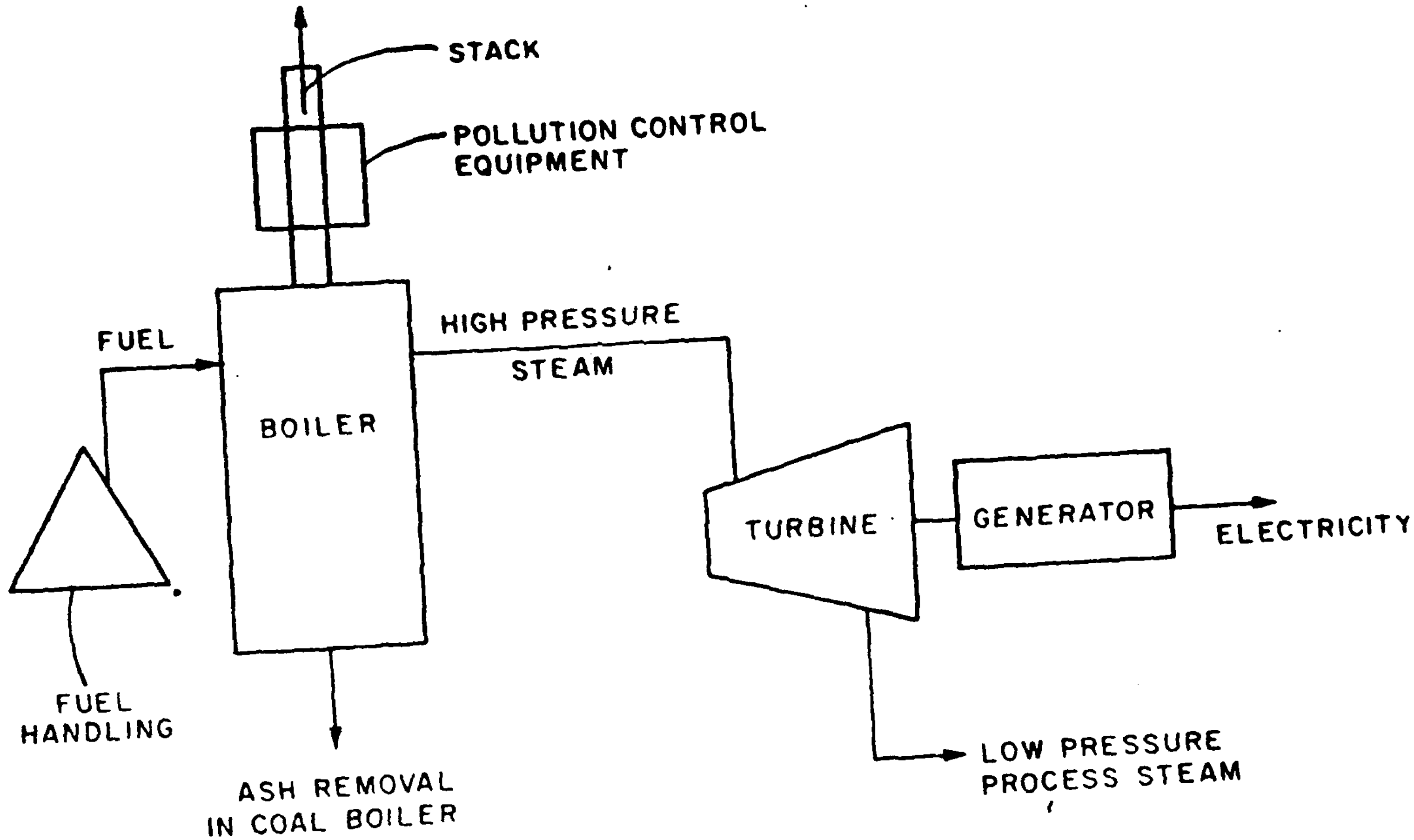

Figure A-20. Schematic of steam turbine topping cycle.

Calculations

$$\begin{pmatrix}\text{Annual}\\ \text{Steam}\\ \text{Output}\\ \text{MBtu/yr}\end{pmatrix} = \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}\text{Btu}\\ \text{Content}\\ \text{Coal}\\ \frac{\text{Btu}}{\text{lbm}}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix}\begin{pmatrix}\frac{2000 \times 365}{3.413 \times 10^6}\\ \frac{\text{lbm - days - MBtu}}{\text{ton - year - Btu}}\end{pmatrix}$$

$$\begin{pmatrix}\text{Annual}\\ \text{Electrical}\\ \text{Output}\\ \text{MWh/yr}\end{pmatrix} = \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}\text{Btu}\\ \text{Content}\\ \text{Coal}\\ \frac{\text{Btu}}{\text{lbm}}\end{pmatrix} \times \begin{pmatrix}\text{Efficiency}\end{pmatrix}\begin{pmatrix}\frac{2000 \times 365}{3.413 \times 10^6}\\ \frac{\text{lbm - days - MWh}}{\text{ton - year - Btu}}\end{pmatrix}$$

$$\begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \$\end{pmatrix} = \begin{pmatrix}\text{Capital}\\ \text{Cost}\\ \text{Factor}\\ \text{\$/MBtu/yr}\end{pmatrix} \times \left[\begin{pmatrix}\text{Annual}\\ \text{Steam}\\ \text{Output}\\ \text{MBtu/yr}\end{pmatrix} \div \begin{pmatrix}\text{Load}\\ \text{Factor}\end{pmatrix}\right]^{\text{Exponent}}$$

$$\begin{pmatrix}\text{Maintenance}\\ \text{Cost}\\ \text{\$/yr}\end{pmatrix} = \begin{pmatrix}\text{Percent}\\ \text{Annualized}\\ \text{Capital}\\ \text{Cost}\end{pmatrix} \times \begin{pmatrix}\text{Annualized}\\ \text{Capital}\\ \text{Cost}\end{pmatrix}$$

$$\begin{pmatrix}\text{Annual}\\ \text{Coal Cost}\\ \text{\$/yr}\end{pmatrix} = \begin{pmatrix}\text{Coal}\\ \text{Cost}\\ \text{\$/ton}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \times \begin{pmatrix}365\\ \frac{\text{Days}}{\text{year}}\end{pmatrix}$$

$$\begin{pmatrix}\text{Area}\\ \text{Required}\\ \text{ft}^2\end{pmatrix} = \begin{pmatrix}\text{Area}\\ \text{Factor}\\ \text{ft}^2/\\ \text{(Ton/Day)}\end{pmatrix} \times \begin{pmatrix}\text{Quantity}\\ \text{Coal}\\ \text{Ton/Day}\end{pmatrix} \qquad \text{(A-36)}$$

to those used in a conventional coal combustion system. These components are discussed in Section A.4.2 and, therefore, will not be described here.

Normally, turbines are optimally designed to extract as much energy as possible from the inlet steam. In doing so, byproduct steam is typically exhausted at saturated, low-pressure conditions not amenable for process use. However, for the steam topping cogeneration system modeled in this study, the steam turbine delivers 150 psig steam. Cost effective electrical generation (i.e., yielding the greatest internal rate of return) dictates inlet turbine steam conditions should be approximately 1000 psig, 900^{o}F (Reference A-23).

A.7.3 Computer Model for Steam-Topping Cogeneration System

Figure A-21 presents a schematic diagram of the inputs, outputs, and parameters of the steam-topping cogeneration computer subroutine. The specific equations used by the cogeneration subroutine to calculate performance and cost are listed below. It is assumed that the steam output from the cogeneration system can meet only process steam demand. Data input to the cogeneration model is discussed in Table A-14.

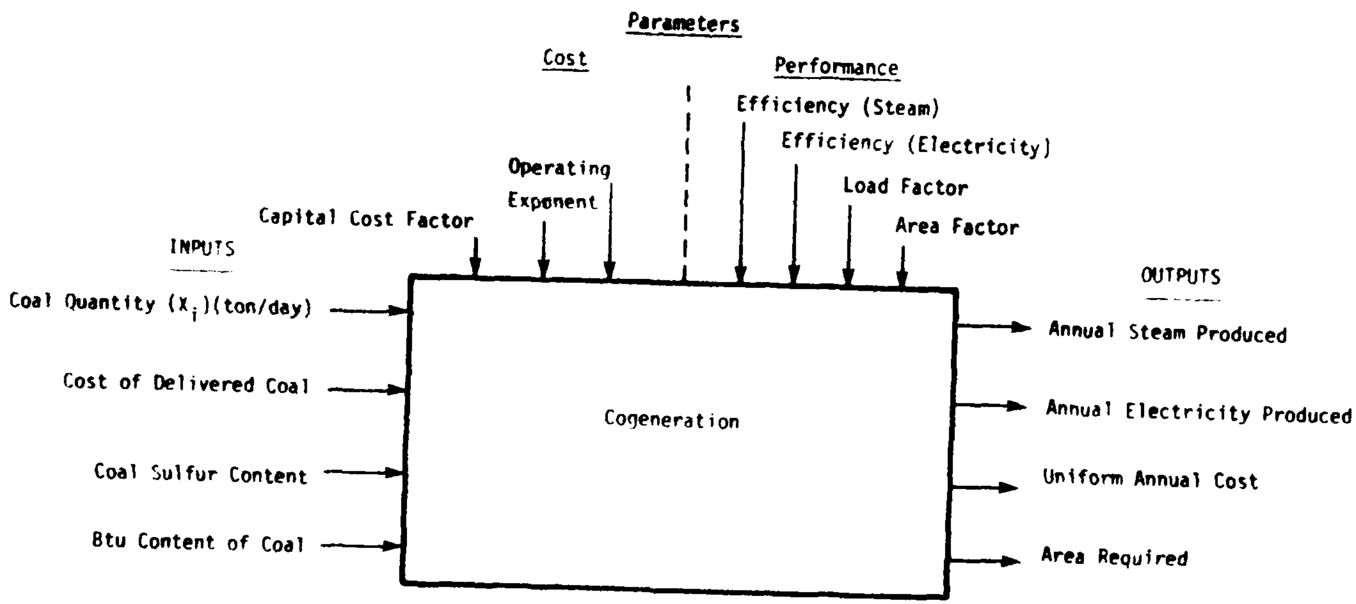

Figure A-21. Schematic of a coal-fired cogeneration system.

TABLE A-14. PERFORMANCE AND COST DATA -- COGENERATION MODEL

	Numerical Value	Comments	References
Performance Data			
Steam Efficiency[a]	70.1%	Based upon a coal-fired boiler efficiency of 85%, and 150 psig process steam conditions	A-1, A-10, A-23, A-45, A-47, A-48
Electric Efficiency[b]	10.8%	Steam turbine inlet and outlet conditions of 1000 psig and 150 psig, respectively	A-1, A-10, A-23, A-45 A-47, A-48
Load Factor[c]	90%		
Area Factor	403 ft^2/(ton/day)	Assuming: (1) 60-day supply of coal stored as a conical pile with a 20° angle of repose, and (2) the conversion facility occupies an equivalent amount of area as the coal pile	A-6
Cost Data			
Capital Cost Factor			
Low Sulfur Coal	197.4 $/(MBtu steam/year)	Capital cost includes cost for coal-fired boiler, coal and ash handling equipment, pollution control equipment, and turbine-generator (see Section A.4.2.1)	A-10, A-23 A-45, A-47, A-48
High Sulfur Coal	202.4 $/(MBtu steam/year		
Exponent	0.80		A-25
Operating Cost	50% Annualized Capital Cost	See Section 2.2.3	A-10, A-47, A-48

T-1889

[a]Efficiency is defined as the ratio of steam energy output to heating value of coal input.
[b]Efficiency is defined as the ratio of electrical energy output to heating value of coal input.
[c]Load factor is defined as the fraction of time a powerplant actually produces energy.

REFERENCES

APPENDIX A

A-1. Salvenson, K. G., M. D. Mac Donald and M. O. Jackson, "Small Boiler Optimization Study," Acurex Corporation/Aerotherm Division, Report No. 77-246, August 1977.

A-2. "Conversion of Refuse to Energy," First International Conference and Technical Exhibition; Montreux-Switzerland, IEEE Catalog No. 75CH1008-2 CRE, November 1975.

A-3. Hileman, and Pyle, "Recycle Energy for Central Heating and Process Steam," Technical Paper presented to International District Heating Association, PGTP-77-19, Pinehurst, North Carolina, June 1977.

A-4. "Project Trash," CEL Technical Report No. R 858, Port Hueneme, CA, December 1977.

A-5. "Alternative Strategies for Optimizing Energy Supply Distribution and Consumption Systems on Naval Bases, Vol. 1, Near-Term Strategies," CR 74.006, N68305-78-C-0009, CEL, Port Hueneme, CA, November 1973.

A-6. "Rock Talk Manual," Kennedy Van Saun #104 Corporation, 1974.

A-7. Proceedings of 1976 National Waste Processing Conference, 1976 National Waste Processing Conference, Boston, MA, The American Society of Mechanical Engineers, May 1976.

A-8. "Decision-Makers Guide in Solid Waste Management," Guide SW-500, Office of Solid Waste Management Programs; U.S. Environmental Protection Agency, pp. iii-158, 1976.

A-9. "The Development of the Basis for an Integrated Alternative Energy Plan for the Sewells Point Naval Complex, Norfolk, Virginia," Battelle's Columbus Laboratories, ERDA, Dept. of the Navy, Atlantic Division, August 1977.

A-10. "Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000, Volume I - Primary Model Documentation," No. EX-76-C-01-2344, Energy and Environment Analysis, Inc., April 1978.

A-11. Renner, J. L., D. E. White, and D. L. Williams, "Assessment of Geothermal Resources of the United States -- Hydrothermal Convection Systems," Geological Survey Circular No. 726, U.S. Department of the Interior, 1975.

A-12. Lineau, P. J., "Utilization and Economics of Geothermal Space Heating in Klamath Falls, Oregon," Oregon Institute of Technology, 1975.

A-13. "Energy Conversion & Economics for Geothermal Power Generation at Heber, California; Valles Caldera, N. M. & Raft River, Idaho," EPRI PB-261 845, November 1976.

A-14. Mathenson, M., and L. J. P. Muffler, "Assessment of Geothermal Resources of the United States -- Geothermal REsources in Hdrothermal Convenction Systems and Conduction-Dominated Areas," Geological Survey Circular No. 726, U.S. Department of the Interior, 1975.

A-15. Larman, W. R., "Digest of Equipment for Converting Solar, Wind, and Geothermal Energy into Electric Power for USN Application Ashore," CEG, Port Hueneme, California, No. 52-784.

A-16. Minerals Yearbook, Vol. I, Metals, Minerals, and Fuel, 1974.

A-17. Nagarvala, Phiroze J., G. C. Ferrell, and L. A. Olver, "Regional Energy System for the Planning and Optimization of National Scenaries Response, Final Report; Clean Coal Energy: Source-To-Use Economics Project," Bechtel Corporation, Prepared for ERDA, Contract No. ERDA-76-109, June 1976.

A-18. Considine, D. M., Energy Technology Handbook, McGraw-Hill, Inc., pp. 5-95 to 9-93, 1977.

A-19. Federal Register, Volume 44, No. 113, June 11, 1979.

A-20. Rifus, B. E., and S. J. White, "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond," EPRI EA-237, Project 437-1, September 1976. Prepared by Manalytics, Inc. .

A-21. Blackwood, T. R., and W. H. Hedley, "Efficiencies in Power Generation," Monsanto Research Generation for EPA. Contract No. 68-02-1320, Task 7, March 1974 or EPA 050/2-74-021.

A-22. Burke, J. M., and M. D. Matson, "Industrial Boiler Fuel Switching," Radian Corporation, August 1978.

A-23. "A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries," Thermo Electron Corporation Prepared for ERDA Report No. PB-255-059.

A-24. Telephone survey with Foster Wheeler, Zurn, Clever-Brooks, and Combustion Engineering.

A-25. Frass, A. P., "Application of the Fluidized Bed Coal Combustion System to the Production of Electric Power & Process Heat," Energy Division, Oak Ridge National Laboratory, AIChE Meeting, Kansas City, MO, April 1976.

A-26. Maloney, Kenneth, L., "Western Coal Use in Industrial Boilers," P-157 KVB Incorporated, for EPA/EPRI Symposium, San Fransicso, California, May 11-13, 1976.

A-27. Askew, A. A., "Economic Treatment and Operation of Boilers, "ASME 76-IPC-PCR-3, presented at the Industrial Power Conference, Memphis, Tennessee, May 16-19, 1976.

A-28. "Utilities Target Manual," NAVFAC, MO-303, Department of the Navy, Naval Facilities Engineering Command, Washington, D.C., May 1972.

A-29. Fennelly, P. F. and D. F. Durocher, "Preliminary Environmental Assessment of Coal Fired Fluidized-Bed Combustion Systems," GCA Corporation, EPA-600/7-77-054, May 1977.

A-30. Keamis, D. L., "Fluidized Bed Combustion Process Evaluation: Phase II - Pressurized Fluidized Bed Coal Combustion Development," EPA-650/7-75-027c, September 1975.

A-31. Jonke, A. A., "Clean Electric Power by Fluidized Bed Combustion of Coal," Argonne National Laboratory, 70th Annual AIChE Meeting, New York, July 1977.

A-32. "Home Heating Conservation Alternatives and the Solar Collector Industry," Federal Energy Administration, PB-253 277, U.S. Commerce Department, March 1976.

A-33. "Survey of the Application of Solar Thermal Energy Systems to Industrial Process Heat," Battelle Columbus Laboratory for Energy Research and Development Administration, January 1977.

A-34. Beckman, Klein, and Duffie, "Solar Heating Design by the f-Chart Method," Solar Energy Laboratory, University of Wisconsin, Madison, 1977.

A-35. ERDA Facilities Solar Design Handbook, August 1977.

A-36. Diamond, S., C. Packard, "The New Mexico Department of Agrigulture Solar Heated and Cooled Buildings," ASME Publication 76-WA/Sol-10, August 1976.

A-37. Nelson, E., P. Overly, and D. Bell, "Survey of EPA Facilities for Solar Energy Applications," Acurex Draft Final Report 78-219, June 1978.

A-38. Shugar, T. A., "Optimization Model for Integrated Alternative Energy Systems," Technical Memorandum No. 51-78-03, CEL, Port Hueneme, CA, November 1977.

A-39. "10-kW Actively Cooled Photovoltaic Concentrator System, Vol. I," Tech. Proposal 2128-78-A, June 1978.

A-40. Kelly, H., "Photovoltaic Power Systems: A Tour Through the Alternatives," Science, Vol. 199, February 1978.

A-41. Coste, W., and M. Lotker," Evaluating a Combined Wind Power/Energy Storage System," Power Engineering, May 1977.

A-42. Zinner, R. P. et al., "Benefit-Cost Methodology Study with Example Application of the Use of Wind Generators," Georgia Institute of Technology, Atlanta, Georgia, N75-31571, National Technical Information Service Dept. Commerce NASA-CR-134864, July 1975.

A-43. Obermeier, J. L., and N. W. Townes, "An Economic Evaluation of Small Scale Wind Powered Electric Generator Systems," ASME Publication No. 76-WA/Ener. 1 g, December 1976.

A-44. "Naval Shore Establishment Energy Research & Development Program First FY-77 Program Review," CEL, Performing Laboratory.

A-45. "The Potential for Cogeneration Development in Six Major Industries by 1985," Resource Planning Associates, Inc., Cambridge. For the Department of Energy, Office of Conservations and Solar Applications, RPA-RA-77-1018, December 1977.

A-46. Williams, R. H., "Industrial Cogeneration," Annual Reviews of Energy, Volume 3, January 30, 1978.

A-47. Leatham, Jr., C. H., "Co-Generation of Steam and Electric Energy for a Manufacturing Plant as Affected by Economy of Scale," paper presented at the ASME Industrial Power Conference, Atlanta, Georgia, October 15-18, 1978, ASME 78-IPC-PWR-4.

A-48. "Cogeneration," Power Engineering, pp 34-42, March 1978.

APPENDIX B

RESULTS OF THE TOP TEN ENERGY CONSUMERS AND THE SAMPLE SURVEY BASES

RESULTS OF THE TOP TEN ENERGY CONSUMERS AND THE SAMPLE SURVEY BASES

Replacing present conventional energy sources with cheaper alternate energy systems can significantly reduce the Navy's energy costs. The NES optimization code identifies the combination of status quo and alternate energy systems that meets all energy demand at minimum cost. Intuitively, one might expect the system that produces energy of lowest cost ($\$/10^6$ Btu) to supply the entire demand. However, due to the variety of energy systems with differing economies of scale and the daily and seasonal variation in demand, matching energy supply to demand is quite complicated. These interrelated factors yield a mix of systems rather than single "winners."

The procedure used by the NES code to determine a least cost mix of energy systems is described in Section B.1. An analysis of results for each of the top ten energy consumers and the sample survey bases are presented in Sections B.2 and B.3, respectively.

B.1 NES OPTIMIZATION PROCEDURE

B.1.1 Single Energy Demand Sector

Process steam and electrical demand vary hourly in response to the 8-hour work cycle, while heating demand varies both hourly and seasonally (see Section 4). The NES code matches these demand variations with energy supplied by the three types of energy systems: baseload, peakload, and solar energy systems. Each of these systems is discussed below. A typical mix of systems is illustrated in Figure B-1.

Baseload Systems

Baseload systems are characterized as central powerplants capable of delivering energy at a lower cost than either solar energy systems or

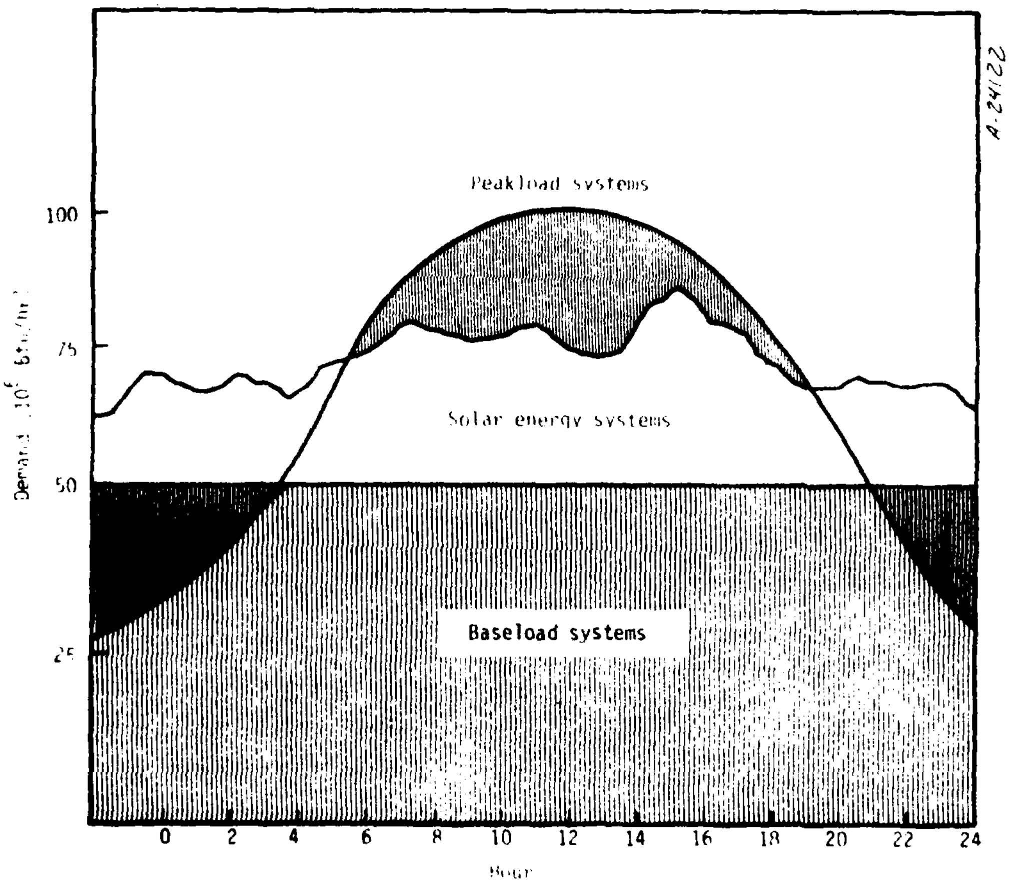

Figure B-1. Typical mix of energy systems.

peaking systems, while generating a constant energy output independent of demand variations. Often these systems produce excess energy during off-peak hours (periods of low demand). A system producing excess energy is cost effective as long as its delivered energy cost -- uniform annual cost (UAC) divided by delivered energy -- remains competitive with other sources. UAC increases with system size as does the proportion of excess to delivery energy, resulting in a higher delivered energy cost (see Figure B-1). Thus, system size increases until delivered energy cost exceeds the energy cost of the closest competitor. This relationship establishes the size of the baseload systems. For this study, FBC, conventional coal, RDF, and cogeneration are baseload systems.

At the Navy's top ten energy consumers in areas meeting federal air quality standards (coal combustion permitted), FBC and cogeneration baseload systems supply nearly 85 percent of the process steam and 95 percent of the electrical demands. Approximately 85 percent is delivered. However, for Navy activities in nonattainment areas, RDF is the only remaining baseload system available. At these locations -- San Diego, Charleston, New London, and Glenview -- RDF meets only 5 to 10 percent of the electrical demand depending upon the quantity of available refuse. Due to RDF's limited contribution, no excess energy is produced.

At the sample survey bases in attainment, conventional coal and cogeneration are the baseload systems supplying approximately 85 percent of the process steam and electrical demands. Again, 85 percent of the produced energy was actually used.

Heating demand varies tremendously during the year in response to weather characteristics at each Navy base. For a given size baseload system, significant amounts of excess energy could be produced during

summer months depending upon the extremes of weather variation at each site. As a result, the proportion of heating demand that baseload systems can cost-effectively supply is limited. For the bases investigated in this study, baseload systems (RDF and FBC) typically meet only 50 percent of the heating demand with nearly 30 percent of the produced energy not delivered.* Although this result is in marked contrast to the performance of baseload systems in the process steam and electricity demand sectors, it is not unexpected. Due to their flexibility, use of diesel fuel peaking systems can deliver energy to match widely varying heating demands less expensively than baseload systems. This conjecture was confirmed by results of the NES code.

Peakload and Solar Energy Systems

As indicated in Figure B-1, energy demand not met by baseload systems is supplied by either peakload or solar energy systems. In contrast to baseload systems, peakload systems generate energy strictly to meet demand with no excess energy produced. They can be easily throttled down to reduce energy production during off-peak hours without penalizing system performance. Oil-fired boilers are peaking systems. Because present methods of storing electricity are not cost effective, solar systems -- specifically photovoltaic and wind generators -- deliver energy depending entirely upon the insolation and wind velocity during a given hour. Consequently, solar systems meet demand only when weather variations coincide with energy demand.

---

*Baseload systems can be throttled down to some extent during summer summer months; however, the present NES code does not model this flexibility.

In general, energy produced by solar systems is not cost competitive with baseload or peaking systems. Only at Pearl Harbor was solar insolation and wind velocity high enough to cost-effectively support solar thermal heating systems and wind-powered generators. At other bases, energy produced by solar systems is typically twice as expensive as energy from baseload or peakload systems. At these bases, demand not met by baseload systems is met by peaking systems -- namely, oil-fired boilers (steam and heat) and commercial electricity.

B.1.2 Multiple Energy Demand Sectors

The previous discussion describes the procedure used by the NES code to minimize energy cost within each demand sector. However, this analysis does not necessarily yield an overall optimum mix of energy systems for the demands taken together. Not only are the demands coupled by constraints on refuse and land availability, but also through technologies like cogeneration which supply energy to more than one demand. In addition, each energy system has different economies of scale. Thus, the mix of systems depends not only on the demand profile, but also on the absolute size of the demand. As a result, larger demands support systems with greater economies of scale. For example, RDF energy is generally cheaper than FBC energy in both the heating and steam sectors, but FBC dominates the larger of the two demands so as to take advantage of FBC's economies of scale. RDF has no economies of scale, and this effectively "forces" RDF into the smaller demand. (Compare results of Norfolk and San Diego.)

In the process steam and electric sectors for the top ten energy consumers, two separate FBC electric and steam systems effectively compete with a combination of cogeneration and FBC-electric systems. Because FBC

and cogeneration have different economies of scale, the optimum mix depends on both the absolute and relative magnitude of the two energy use sectors (see Section 5). Due to the complicated relationship between variables, identifying the most cost-effective mix of energy systems for more than one demand requires computer analysis.

B.1.3 General Discussion of Tabulated Results

Sections B.2 and B.3 contain the tabulated results of the top ten energy consumers and the sample survey bases as determined by the NES optimization program. An analysis of each base is given and two tables are presented.

The first table lists the delivered energy, produced energy, and produced energy cost for the optimum mix of energy systems. As a result of both seasonal and daily demand variation, energy systems can be economically sized to produce excess energy during off-peak demands. The actual price for energy charged to the consumer is delivered energy cost, not produced energy cost as listed in the tables. This delivered energy cost is calculated as the ratio of system uniform annual cost (proportional to produced energy) to actual delivered energy (10^6 Btu/hr). Thus, the price of delivered energy is higher than the price of produced energy and it increases substantially as excess energy is produced. In effect, the consumer is paying for but not completely utilizing the capabilities of a larger system. Produced energy costs for "losing" systems (given in parenthesis) are calculated assuming these systems produced an equivalent amount of energy as the largest optimum "winning" system within each energy use sector. This provides an equal basis for comparison because effects of excess energy are not included.

The second table presented for each base compares initial capital cost, total annual cost, equivalent oil consumption, and area requirement

of the optimum mix of energy systems with the same parameters for conventional systems alone delivering the same amount of energy.

In many cases energy costs for various alternate systems are quite close to one another. At Pensacola in the heating sector, produced energy costs for RDF, FBC, and conventional coal systems are within $\$0.10/10^6$ Btu of each other. Thus small perturbations in capital, fuel, or operation cost and system performance could enable another system to be more cost effective. An analysis must be performed to assess the sensitivity of results to changes in input parameters. Nevertheless, money saved and oil displaced by implementing a mix of alternate energy systems will remain approximately the same regardless of which alternate system is chosen. Consequently, the tabulated results given for each base are a true indicator of potential market penetration of energy systems and their subsequent savings. A comprehensive analysis of each base is required to accurately specify particular energy systems. A detailed energy audit should be conducted and the compatibility of energy systems with existing fuel sources (diesel, coal, and natural gas) and distribution networks (i.e., process steam) should be investigated.

B.2 TOP TEN ENERGY CONSUMERS

Overall trends of the top ten energy consumers were described in Section 5. However, the actual mix of energy systems at each base deviates from these overall trends depending upon a number of factors including the absolute size and relative magnitude of the energy use sectors, the quantity of available refuse, and seasonal insolation and wind velocity. In this section, the unique characteristics that determine the optimum mix of energy systems for each top ten base are identified and two tables are presented.

B.2.1 Norfolk, Virginia

Norfolk is the largest single Navy energy consumer in the continental United States and the optimum mix of systems reflect the overall trends discussed in Section 5. Its size allows energy systems with economies of scale to significantly reduce energy cost. Of the energy systems investigated in this study, FBC benefits most from economics of scale and would be expected to supply substantial quantities of energy at Norfolk. As shown in Tables B-1a and B-1b, FBC meets approximately 60 percent of the heating, 30 percent of the process steam, and 80 percent of the electricity demands. This energy is supplemented by cogeneration in the steam and electricity sectors.

As discussed in Section 5, RDF typically supplies energy to meet the smaller heating and steam sectors. At Norfolk, RDF supplies the process steam demand, which is less than the heating demand. This enables the economies of scale associated with FBC to further reduce costs in the larger heating sector.

Average wind velocity (8.7 mph) and insolation (1339 Btu/ft^2-day) at Norfolk are typical of other top ten energy consumers. Under these weather conditions, wind generators and solar energy systems are not competitive with conventional or other alternative energy sources.

Summary

For simplicity, we assumed that heating and process steam are currently provided by oil-fired boilers, and electrical demand is met by purchases of commercial electricity. Further assuming that all existing oil-fired boilers are replaced with new equipment, if Norfolk invests an additional $52 million in RDF, FBC, and cogeneration alternate energy

systems, it can potentially reduce its annual cost for energy by $28 million. This represents a simple pay back of 2 years and reduces fuel oil consumption by 70 percent.

TABLE B-1a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR NORFOLK, VIRGINIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	FBC, and oil-fired boilers
	FBC	1,390.0	2,294.0	3.89	
	Solar thermal	--	--	(15.16)	
	Conventional coal	--	--	(4.12)	
	Oil-fired boilers	852.9	852.9	8.92	
Process Steam	RDF	10.7	10.7	4.53	RDF, FBC, and commercial
	FBC	495.7	495.7	4.99	
	Conventional coal	--	--	(4.77)	
	Cogeneration	956.6	1,192.0	5.25	
	Oil-fired boilers	265.7	265.7	9.36	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, and oil-fired boilers
	FBC	1,495.0	1,870.0	9.05	
	Photovoltaic	--	--	(63.84)	
	5-kW wind	--	--	(151.39)	
	200-kW wind	--	--	(71.37)	
	1500-kW wind	--	--	(95.25)	
	Conventional coal	--	--	(10.87)	
	Cogeneration	204.0	204.0	5.25	
	Commercial	88.3	88.3	22.48	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-011

TABLE B-1b. SUMMARY OF RESULTS: NORFOLK, VIRGINIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	FBC Oil-fired boilers	1,390.0 852.9	62.0 38.0	0.61 1.00	12.94 5.23	8.92 7.61	-- 190.37	11.91 --
	Oil-fired boilers alone	2,243.0	100.0	1.00	8.54	19.13	500.61	--
Steam	RDF FBC Cogeneration Oil-fired boilers	10.7 495.7 956.6 266.0	0.6 28.7 55.3 15.4	1.00 1.00 0.80 1.00	0.20 5.12 15.59 2.34	0.05 2.47 7.32 2.49	-- -- -- 65.89	0.22 2.86 8.33 --
	Oil-fired boilers alone	1,729.0	100.0	1.00	5.53	16.09	442.1	--
Electricity	FBC Cogeneration Commercial	1,494.9 204.0 88.3	83.6 11.4 5.0	0.80 1.00 1.00	25.53 -- --	16.92 -- 1.98	-- -- --	22.30 8.33 --
	Commercial alone	1,787.0	100.0	1.00	--	40.17	--	--
Total Optimum Mix		5,759.0	100.0	0.79	66.95	47.76	256.3	45.62
Total Commercial/Oil Alone		5,759.0	100.0	1.00	14.07	75.39	942.7	--

Savings = 27.63×10^6/yr
Oil saved = 586,460 barrels/yr

EE-T-012

B.2.2 San Diego, California

With Coal

The optimum mix of energy systems at San Diego is typical of results obtained for other top ten energy consumers (refer to Section 5 for a detailed discussion). As shown in Table B-2a, process steam demand is met by cogeneration and oil-fired boilers, while electrical demand is met by a combination of cogeneration, FBC, and to a small extent, commercial sources. RDF, FBC, and oil-fired boilers meet heating demand.

Because the average wind velocity at San Diego is only 5.8 mph, electricity produced by wind energy systems is extremely expensive. For example, electricity produced by a 1500-kW system costs over $\$1000/10^6$ Btu (see Table B-2a). Due to coastal fog, insolation at San Diego is low at 1338 Btu/ft^2-day. As a result, solar thermal and photovoltaic systems deliver energy at twice the cost of energy compared to conventional sources.

Without Coal

San Diego is located in a nonattainment region for NO_x and particulates. This restricts use of any energy source which may add to the NO_x or particulate levels, specifically, coal combustion systems. If proposed utility restrictions are extended to industrial size units, the Navy could be prevented from using coal combustion in San Diego as well. The optimum mix of energy systems at San Diego without coal combustion is given in Tables B-2c and B-2d. As shown, all 190 tons/day of available refuse is consumed to generate electricity. Alternately, RDF rather than oil-fired boilers could supply heat or process steam. However, overall cost for energy is minimized if purchases of expensive commercial electricity ($\$36/10^6$ Btu) are reduced rather than reducing use of relatively inexpensive oil-fired boilers ($\$8/10^6$ Btu).

Summary

If coal combustion systems are permitted in San Diego, employing RDF, FBC, and cogeneration systems can markedly reduce payments for energy by $57 million per year. This requires an initial capital investment of $49 million, or a simple payback of less than 1 year. However, if coal systems are restricted due to nonattainment, a reduction of only $4 million per year is possible and would require a $7 million investment in a RDF-electricity system. This represents a simple payback of 2 years.

TABLE B-2a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR SAN DIEGO, CALIFORNIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	43.5	43.5	4.08	RDF, FBC, and oil-fired boilers
	FBC	575.9	896.5	4.29	
	Solar thermal	--	--	(15.77)[a]	
	Conventional coal	--	--	(4.57)	
	Oil-fired boilers	301.4	301.4	8.62	
Process Steam	RDF	--	--	(4.53)	Cogeneration and oil-fired boilers
	FBC	--	--	(4.44)	
	Conventional coal	--	--	(4.79)	
	Cogeneration	1,427.0	1,656.0	5.22	
	Oil-fired boilers	260.5	260.5	9.31	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, commercial
	FBC	1,620.0	1,804.0	9.16	
	Photovoltaic	--	--	(74.01)	
	5-kW wind	--	--	(464.1)	
	200-kW wind	--	--	(248.4)	
	1500-kW wind	--	--	(1,151.8)	
	Conventional coal	--	--	(11.15)	
	Cogeneration	283.3	283.3	5.22	
	Commercial	26.3	26.3	36.33	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-013

TABLE B-2b. SUMMARY OF RESULTS: SAN DIEGO, CALIFORNIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	43.5	4.7	1.0	0.74	0.18	--	0.80
	FBC	575.9	62.5	0.64	7.03	3.85	--	5.86
	Oil-fired boilers	301.4	32.8	1.0	1.40	2.60	67.3	--
	Oil-fired boilers alone	920.8	100.0	1.0	2.76	7.69	205.5	--
Steam	Cogeneration	1,427.0	84.6	0.86	20.79	10.11	--	14.58
	Oil-fired boilers	260.5	15.4	1.0	2.29	2.42	58.1	--
	Oil-fired boilers alone	1,687.0	100.0	1.0	5.40	15.60	376.7	--
Electricity	FBC	1,620.0	84.0	0.90	24.94	16.53	--	27.10
	Cogeneration	283.3	14.7	1.0	--	--	--	14.58
	Commercial	26.3	1.3	1.0	--	0.96	--	--
	Commercial alone	1,930.0	100.0	1.0	--	70.10	--	--
Total Optimum Mix		4,538.0	100.0	0.86	57.19	36.65	125.4	62.92
Total Commercial/Oil Alone		4,538.0	100.0	1.0	8.16	93.39	582.2	--

Savings = \$56.7 x 10^6/yr
Oil saved = 456,800 barrels/yr

EE-T-014

TABLE B-2c. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR SAN DIEGO, CALIFORNIA NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost (\$/10^6 Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	Oil-fired boilers
	Solar thermal	--	--	(15.77)	
	Oil-fired boilers	920.8	920.8	8.35	
Process Steam	RDF	--	--	(4.53)	Oil-fired boilers
	Oil-fired boilers	1,687.0	1,687.0	8.38	
Electricity	RDF	143.6[b]	143.6	10.60	RDF and commercial
	Photovoltaic	--	--	(74.01)	
	5-kW wind	--	--	(464.11)	
	200-kW wind	--	--	(248.4)	
	1500-kW wind	--	--	(1,151.8)	
	Commercial	1,786.0	1,786.0	36.33	

[a] All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.
[b] Limit of available refuse -- 190 ton/day

EE-T-015

TABLE B-2d. SUMMARY OF RESULTS: SAN DIEGO, CALIFORNIA
NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Oil-fired boilers	920.8	100.0	1.0	2.76	7.69	205.5	--
	Oil-fired boilers alone	920.8	100.0	1.0	2.76	7.69	205.5	--
Steam	Oil-fired boilers	1,687.0	100.0	1.0	5.40	15.60	418.4	--
	Oil-fired boilers alone	1,687.0	100.0	1.0	5.40	15.60	418.4	--
Electricity	RDF Commercial	143.6 1,786.0	7.44 92.56	1.0 1.0	7.03 --	1.52 64.89	-- --	6.215 --
	Commercial alone	1,930.0	100.0	1.0	--	70.10	--	--
Total Optimum Mix		4,537.0	100.0	1.0	15.19	89.70	623.9	6.215
Total Commercial/Oil Alone		4,537.0	100.0	1.0	8.16	93.39	623.9	--

Savings = $ 3.69 x 10^6/yr
Oil saved = 0 barrels/yr

EE-T-016

B.2.3 Philadelphia, Pennsylvania

Of the top ten bases evaluated, Philadelphia has the largest heating demand. Economies of scale enable FBC to supply this heat at lower cost than other systems, particularly RDF. Consequently, RDF preferentially supplies more process steam than heat compared with the typical mix of systems at other bases. NES results are given in Tables B-3a and B-3b.

In accordance with overall trends indicated by the top ten energy consumers, process steam demand is met primarily by cogeneration, while electrical demand is met by a combination of cogeneration and FBC. The remaining heating and process steam demand is met by oil-fired boilers. Purchases of commercial electricity meet the remaining electrical demand. Wind velocity (9.3 mph) and insolation (1339 Btu/ft^2-day) at Philadelphia are not sufficient to economically support wind and solar systems.

Summary

Replacing present energy sources with conventional oil-fired boilers would require a \$15 x 10^6 capital investment. However, investing an additional \$30 x 10^6 in a mix of RDF, FBC, cogeneration and oil-fired boilers could net an annual savings of \$17 x 10^6. This represents a simple payback of 2 years and reduces oil consumption by 50 percent.

TABLE B-3a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR PHILADELPHIA, PENNSYLVANIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	7.78	15.70	4.08	RDF, FBC, and oil-fired boilers
	FBC	1,170.0	1,404.0	4.06	
	Solar thermal	--	--	(12.63)[a]	
	Conventional coal	--	--	(4.27)	
	Oil-fired boilers	1,560.0	1,560.0	9.05	
Process Steam	RDF	22.56	22.56	4.53	RDF, Cogeneration oil-fired boilers
	FBC	--	--	(4.76)	
	Conventional coal	--	--	(4.95)	
	Cogeneration	639.7	748.5	5.43	
	Oil-fired boilers	117.1	117.1	10.26	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, and commercial
	FBC	545.4	621.8	10.11	
	Photovoltaic	--	--	(63.84)	
	5-kW wind	--	--	(135.57)	
	200-kW wind	--	--	(64.11)	
	1500-kW wind	--	--	(84.73)	
	Conventional coal	--	--	(11.61)	
	Cogeneration	128.1	128.1	5.43	
	Commercial	26.65	26.65	27.01	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-017

TABLE B-3b. SUMMARY OF RESULTS: PHILADELPHIA, PENNSYLVANIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	7.78	0.3	0.50	0.27	0.06	--	0.29
	FBC	1,170.0	42.7	0.83	9.41	5.70	--	7.29
	Oil-fired boilers	1,560.0	57.0	1.0	10.75	14.11	384.2	--
	Oil-fired boilers alone	2,737.0	100.0	1.0	12.80	23.74	611.1	--
Steam	RDF	22.56	2.9	1.0	0.42	0.10	--	0.46
	Cogeneration	639.7	82.1	0.85	10.75	4.76	--	5.23
	Oil-fired boilers	117.1	15.0	1.0	1.05	1.20	29.0	--
	Oil-fired boilers alone	779.4	100.0	1.0	2.49	7.25	193.3	--
Electricity	FBC	545.4	77.9	0.88	12.48	6.29	--	7.42
	Cogeneration	128.1	18.3	1.0	--	--	--	--
	Commercial	26.65	3.8	1.0	--	0.72	--	--
	Commercial alone	700.15	100.0	1.0	--	18.91	--	--
Total Optimum Mix		4,217.0	100.0	0.91	45.13	32.94	377.2	20.69
Total Commercial/Oil Alone		4,217.0	100.0	1.0	15.29	49.90	804.4	--

Savings = \$16.96 x 10^6/yr
Oil saved = 427,200 barrels/yr

EE-T-017

B.2.4 Charleston, South Carolina

With Coal

Charleston is located in a temperate climate, and heating demand is small compared to other bases investigated. In the smaller heating sector, heat produced by RDF is much less expensive than that produced by FBC due to FBC's economies of scale. The cost for heat produced by RDF is (\$4.10/10^6 Btu versus \$5.30/10^6 Btu) for heat produced by FBC. Tables B-4a and B-4b show that RDF supplies 22 percent of the heating requirements. RDF would optimally supply more energy but its contributions are limited by 70 tons/day of available refuse.

The optimum mix of systems in the process steam and electricity sectors reflect overall trends for the top ten energy consumers discussed in Section 5. Cogeneration supplies 85 percent of the steam demand; cogeneration and FBC combine to supply 95 percent of the electrical demand.

Low wind velocity (8.1 mph) and insolation (1516 Btu/ft^2-day) at Charleston is similar to other sites investigated. Consequently, energy produced by wind and photovoltaic systems costs twice as much as commercial electricity.

Without Coal

The Charleston area does not presently meet proposed federal NO_x and particulate air quality standards. Therefore, enforcement of nonattainment regulations would prevent further use of energy systems which produce NO_x or particulates, specifically coal combustion. Assuming this restriction is applied to industrial size units, RDF would be the only cost-effective alternative energy source at Charleston. As indicated in Tables B-4c and B-4d, 70 tons/day of available refuse is consumed to produce electricity. Because commercial electricity is the

most expensive energy source, RDF preferentially supplies electricity rather than process steam or heat.

Summary

If coal combustion is permitted in the Charleston area, investing $32 million in an optimum mix of RDF, FBC, cogeneration, and oil-fired boilers could reduce annual payments for energy by $16 million. This represents a simple 2-year return on investment and reduces fuel oil consumption by 288,700 barrels per year. However, if coal combustion is restricted due to nonattainment, a capital investment of $2.6 million in an RFD-fired electrical generation system is the only possible alternative. Such a system would reduce annual energy cost by only $640,000. This yields a relatively unattractive 4-year return on investment for a system that will reduce purchases of commercial electricity but not reduce consumption of fuel oil.

TABLE B-4a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR CHARLESTON, SOUTH CAROLINA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost (\$/10^6 Btu)	Optimum Mix
Heating	RDF	118.2	124.1	4.08	RDF, FBC, and oil-fired boilers
	FBC	116.4	158.3	5.33	
	Solar thermal	--	--	(14.22)[a]	
	Conventional coal	--	--	(4.54)	
	Oil-fired boilers	300.6	300.6	9.61	
Process Steam	RDF	--	--	(4.53)	Cogeneration and oil-fired boilers
	FBC	--	--	(3.81)	
	Conventional coal	--	--	(4.03)	
	Cogeneration	952.6	1,110.0	5.27	
	Oil-fired boilers	166.6	166.6	9.40	
Electricity	RDF	--	--	(4.53)	FBC, cogeneration, and commercial
	FBC	791.1	882.5	9.72	
	Photovoltaic	--	--	(63.84)	
	5-kW wind	--	--	(94.35)	
	200-kW wind	--	--	(47.23)	
	1500-kW wind	--	--	(48.93)	
	Conventional coal	--	--	(11.35)	
	Cogeneration	190.1	190.1	5.27	
	Commercial	46.55	46.55	22.64	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-019

TABLE B-4b. SUMMARY OF RESULTS: CHARLESTON, SOUTH CAROLINA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	118.2	22.1	0.95	2.10	0.51	--	2.29
	FBC	116.4	21.7	0.74	2.28	0.84	--	0.82
	Oil-fired boilers	300.6	56.2	1.0	2.32	2.89	67.1	--
	Oil-fired boilers alone	535.2	100.0	1.0	2.72	4.79	119.5	--
Steam	Cogeneration	952.6	85.1	0.86	14.73	5.85	--	7.77
	Oil-fired boilers	166.6	14.9	1.0	1.50	1.57	41.3	--
	Oil-fired boilers alone	1,119.0	100.0	1.0	3.58	9.68	277.6	--
Electricity	FBC	791.1	77.0	0.90	15.67	8.58	--	10.52
	Cogeneration	190.1	18.5	1.0	--	--	--	--
	Commercial	46.55	4.5	1.0	--	1.05	--	--
	Commercial alone	1,027.8	100.0	1.0	--	23.27	--	--
Total Optimum Mix		2,682.0	100.0	0.90	38.60	21.29	108.4	21.40
Total Commercial/Oil Alone		2,682.0	100.0	1.0	6.30	37.74	397.1	--

Savings = \$16.45 x 10^6/yr
Oil saved = 288,700 barrels/yr

EE-T-021

TABLE B-4c. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR CHARLESTON, SOUTH CAROLINA NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	Oil-fired boilers
	Solar thermal	--	--	(14.22)	
	Oil-fired boilers	535.2	535.2	8.97	
Process Steam	RDF	--	--	(10.60)	Oil-fired boilers
	Oil-fired boilers	1,119.0	1,119.0	8.65	
Electricity	RDF	52.9[b]	52.9	10.60	RDF and commercial
	Photovoltaic	--	--	(63.34)	
	5-kW wind	--	--	(94.35)	
	200-kW wind	--	--	(47.23)	
	1500-kW wind	--	--	(48.93)	
	Commercial	974.8	974.8	22.64	

[a]All parentheses denote energy costs based on the energy produced by the largest optimum model within each energy use sector.
[b]Limit of available refuse -- 70 ton/day

EE-T-022

TABLE B-4d. SUMMARY OF RESULTS: CHARLESTON, SOUTH CAROLINA
NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Oil-fired boilers	535.2	100.0	1.0	2.72	4.79	119.5	--
	Oil-fired boilers alone	535.2	100.0	1.0	2.72	4.79	119.5	--
Steam	Oil-fired boilers	1,119.0	100.0	1.0	3.58	9.68	277.5	--
	Oil-fired boilers alone	1,119.0	100.0	1.0	3.58	9.68	277.5	--
Electricity	RDF Commercial	52.9 974.8	5.1 94.9	1.0 1.0	2.59 --	0.56 22.07	-- --	2.29 --
	Commercial alone	1,028.0	100.0	1.0	--	23.27	--	--
Total Optimum Mix		2,682.0	100.0	1.0	8.89	37.10	397.0	2.29
Total Commercial/Oil Alone		2,682.0	100.0	1.0	6.30	37.74	397.0	--

Savings = \$640,000/yr
Oil saved = 0 barrels/yr

EE-T-023

B.2.5 Pearl Harbor, Hawaii

Due to the high cost of transporting fuel to Hawaii, conventional energy cost at Pearl Harbor is the highest among the bases investigated. In fact, no coal systems were included in this analysis because coal transportation is prohibitively expensive. However, Pearl Harbor's extremely high insolation and wind velocity combined with high conventional energy costs enables solar thermal and wind energy systems to be cost effective. As discussed in Section B.1, the size of the wind and solar energy systems is determined by an hourly match of energy produced with energy demand. Solar thermal supplies 61 x 10^9 Btu/yr of heat, nearly 10 percent of the heating demand, at a cost of \$10.99/10^6 Btu. The oil-fired heating cost is \$12.45/10^6 Btu. Fifteen-hundred kW wind systems supply 293 x 10^6 Btu/yr of electricity (20 percent of the electrical demand) at a cost of \$27.88/10^6 Btu compared to commercial electric cost of \$32.00/10^6 Btu. Table B-5a presents detailed comparative cost data.

All of the 70 tons/day of refuse available at Pearl Harbor is consumed to produce heat, process steam, and electricity. As evidenced by a 100 percent load factor (delivered energy/produced energy given in Table B-5b), RDF supplies the baseload portion of the demand in all three energy use sectors.

Summary

Wind and solar energy systems are extremely capital intensive. Replacing oil-fired boilers with an optimum mix of RDF, solar, wind, and oil-fired boilers requires an additional capital investment of \$52 x 10^6. This reduces annual cost by only \$2.2 million yielding a 23-year return on investment -- significantly higher than the 2-year ROI typical of bases that can economically employ coal combustion systems (FBC and cogeneration).

TABLE B-5a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR PEARL HARBOR, HAWAII NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($\$/10^6$ Btu)	Optimum Mix
Heating	RDF	38.2	38.2	4.08	RDF, solar thermal and oil-fired boilers
	Solar thermal	61.4	63.1	10.99	
	Oil-fired boilers	532.4	532.4	12.45	
Process Steam	RDF	31.6	31.6	4.53	RDF and oil-fired boilers
	Oil-fired boilers	550.2	550.2	13.91	
Electricity	RDF	21.6	21.6	10.60	RDF and 1500-kW wind and commercial
	Photovoltaic	--	--	(50.54)	
	5-kW wind	--	--	(62.64)	
	200-kW wind	--	--	(38.38)	
	1500-kW wind	293.4	298.9	27.88	
	Commercial	810.7	810.7	32.00	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-024

TABLE B-5b. SUMMARY OF RESULTS: PEARL HARBOR, HAWAII
(NOT INCLUDING COAL MODELS)

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En./Produced En.	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	38.2	6.1	1.0	0.65	0.16	--	0.71
	Solar thermal	61.4	9.7	0.97	5.25	0.67	--	36.89
	Oil-fired boilers	532.4	84.2	1.0	1.32	6.63	118.8	--
	Oil-fired boilers alone	632.0	100.0	1.0	1.48	7.85	141.07	--
Steam	RDF	31.6	5.4	1.0	0.59	0.14	--	0.65
	Oil-fired boilers	550.2	94.6	1.0	1.80	7.65	122.80	--
	Oil-fired boilers alone	581.8	100.0	1.0	1.86	8.09	129.86	--
Electricity	RDF	21.6	1.9	1.0	1.06	0.23	--	0.94
	1500-kW wind	293.3	26.1	0.98	45.00	8.33	--	99.00
	Commercial	810.7	72.0	1.0	--	25.94	--	--
	Commercial alone	1,126.0	100.0	1.0	--	36.03	--	--
Total Optimum Mix		2,340.0	100.0	0.997	55.67	49.75	241.63	138.18
Total Commercial/Oil Alone		2,340.0	100.0	1.0	3.34	51.97	270.93	--

Savings = $2.2 x 10^6/yr
Oil saved = 29,300 barrels/yr

EE-T-026

B.2.6 Great Lakes, Illinois

Great Lakes is unique among the top ten energy consumers in that it has substantial heating and process steam requirements but low electrical demand. These particular demand profiles, as well as their magnitude, are the primary factors determining the mix of alternate energy systems. Economies of scale enable FBC to meet the large heating demand of 1.58×10^{12} Btu/yr less expensively than RDF -- specifically, \$3.28/10^6 Btu compared to \$4.08/10^6 Btu. NES results for Great Lakes are listed in Tables B-6a and B-6b. Electrical demand at Great Lakes is insufficient to consume the by-product electricity generated by the steam-topping cogeneration system. Therefore the particular cogeneration system modeled in this study does not cost-effectively match energy produced to energy demand at Great Lakes. Two separate FBC systems meet the process steam and electrical demand at lower cost than a combination of cogeneration and FBC electricity system. This agrees with the analysis presented in Section 5.

Insolation at Great Lakes is low with a corresponding high cost of energy produced by solar thermal and photovoltaic systems: \$10.7/10^6 Btu and \$80.6/10^6 Btu, respectively.

Although wind velocity is a relatively high 8 to 11 knots average at Great Lakes, it is not high enough to economically support wind energy systems. A 1500-kW wind generator produces electricity at approximately \$40/10^6 Btu compared to commercial electricity cost of \$20/10^6 Btu.

<u>Summary</u>

Although the NES code chose to implement three separate FBC systems, in reality a single facility capable of supplying all three demands could be more cost effective. Unfortunately, current modeling in the NES code does not include such a system.

Results using the present code indicate that investing an additional $25 million in oil-fired boilers and separate FBC systems to replace conventional oil-fired boilers yields an annual energy cost savings of $9 million and reduces fuel oil consumption by 578,500 barrels/yr. This represents a 2.5-year return on investment.

TABLE B-6a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR GREAT LAKES, ILLINOIS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	FBC and oil-fired boilers
	FBC	1,115.0	1,847.0	3.28	
	Solar thermal	--	--	(19.70)	
	Conventional coal	--	--	(3.50)	
	Oil-fired boilers	460.1	460.1	9.07	
Process Steam	RDF	--	--	(4.53)	FBC and oil-fired boilers
	FBC	926.1	1,132.0	3.80	
	Conventional coal	--	--	(4.03)	
	Cogeneration	--	--	(3.99)	
	Oil-fired boilers	109.6	109.6	9.92	
Electricity	RDF	--	--	(10.60)	FBC and commercial
	FBC	368.9	547.4	9.98	
	Photovoltaic	--	--	(80.57)	
	5-kW wind	--	--	(82.63)	
	200-kW wind	--	--	(45.68)	
	1500-kW wind	--	--	(39.14)	
	Conventional coal	--	--	(10.09)	
	Cogeneration	--	-	(3.99)	
	Commercial	28.3	28.3	20.83	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-026

TABLE B-6b. SUMMARY OF RESULTS: GREAT LAKES, ILLINOIS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	FBC	1,115.0	70.8	0.60	11.24	6.05	--	9.59
	Oil-fired boilers	460.1	29.2	1.0	2.62	4.17	102.7	--
	Oil-fired boilers alone	1,575.1	100.0	1.0	5.29	13.23	351.6	--
Steam	FBC	926.1	89.4	0.82	8.76	4.30	--	6.53
	Oil-fired boilers	109.6	10.6	1.0	1.19	1.09	27.18	--
	Oil-fired boilers alone	1,036.0	100.0	1.0	3.31	9.57	256.9	--
Electricity	FBC	368.9	92.9	0.67	9.87	5.46	--	1.88
	Commercial	28.3	7.1	1.0	--	0.59	--	--
	Commercial alone	397.2	100.0	1.0	--	8.27	--	--
Total Optimum Mix		3,008.0	100.0	0.73	33.68	21.66	129.9	18.0
Total Commercial/Oil Alone		3,008.0	100.0	1.0	8.60	31.07	608.4	--

Savings = \$9.41 x 10^6/yr
Oil saved = 478,500 barrels/yr

EE-T-027

B.2.7 Portsmouth, Virginia

Portsmouth is typical of other bases analyzed. Total energy demand is split evenly among the heating, process steam, and electrical generation sectors. However, commercial electricity cost ($\$33.02/10^6$ Btu) is markedly higher than at other bases. As a cost-effective alternative to expensive commercial electricity, cogeneration and FBC systems combine to meet 97 percent of the total electrical demand (see Table B-7b). In contrast, for other top ten energy consumers, FBC and cogeneration systems met only 90 to 95 percent of the electrical demand.

In the heating sector, RDF supplies the base demand, while FBC and oil-fired boilers supply the peak demand. As indicated in Table B-7b, nearly 40 percent of the heat produced by the FBC system is not delivered. This reflects the wide seasonal variation in weather at Portsmouth which results in significant heating system downtime during warm summer months. In reality, the FBC system would be throttled down to reduce excess energy production, but this option is not presently available in the NES program.

Cogeneration supplies most of the process steam requirements, and the remaining portion is met by RDF and oil-fired boilers. Although RDF is cost effective, its relatively insignificant contribution would probably not justify implementation.

Insolation (1339 Btu/ft^2-day) and wind velocity (8.7 mph) are average at Portsmouth. Consequently, solar and wind energy systems are not cost effective. As shown in Table B-7a, the price of solar thermal energy was $\$15.8/10^6$ Btu versus $\$9.2/10^6$ Btu for oil-fired boilers,

while the price of electricity produced by a 1500-kW wind system was $\$95.5/10^6$ Btu versus $\$33.0/10^6$ Btu for commercial electricity.

Summary

Investing an additional $27 million in a mix of alternate energy systems rather than conventional oil-fired boilers can potentially reduce annual cost for energy by $18 million. This yields a 1.5-year simple return on investment and cuts use of fuel oil by 248,800 barrels/yr.

TABLE B-7a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR PORTSMOUTH, VIRGINIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	80.6	83.3	4.08	RDF, FBC, and oil-fired boilers
	FBC	342.8	562.8	4.48	
	Solar thermal	--	--	(15.77)[a]	
	Conventional coal	--	--	(4.61)	
	Oil-fired boilers	467.0	467.0	9.19	
Process Steam	RDF	4.0	4.0	4.53	RDF, cogeneration and oil-fired boilers
	FBC	--	--	(4.78)	
	Conventional coal	--	--	(4.97)	
	Cogeneration	618.3	716.6	5.44	
	Oil-fired boilers	115.7	115.7	9.35	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, and commercial
	FBC	560.8	648.8	10.06	
	Photovoltaic	--	--	(79.40)	
	5-kW wind	--	--	(151.39)	
	200-kW wind	--	--	(71.58)	
	1500-kW wind	--	--	(95.49)	
	Conventional coal	--	--	(11.58)	
	Cogeneration	122.7	122.7	5.44	
	Commercial	19.2	19.2	33.02	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-028

TABLE B-7b. SUMMARY OF RESULTS: PORTSMOUTH, VIRGINIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	80.6	9.1	0.97	1.41	0.34	--	1.54
	FBC	342.8	38.5	0.61	5.19	2.52	--	2.92
	Oil-fired boilers	467.0	52.4	1.0	3.63	4.29	104.2	--
	Oil-fired boilers alone	890.0	100.0	1.0	4.56	7.79	198.7	--
Steam	RDF	4.0	0.5	1.0	0.07	0.02	--	0.08
	Cogeneration	618.3	83.8	0.86	10.38	3.90	--	5.01
	Oil-fired boilers	115.7	15.7	1.0	1.01	1.08	28.7	--
	Oil-fired boilers alone	738.0	100.0	1.0	2.36	6.87	183.0	--
Electricity	FBC	560.8	79.8	0.86	12.83	6.53	--	7.74
	Cogeneration	122.7	17.5	1.0	--	--	--	--
	Commercial	19.2	2.7	1.0	--	0.63	--	--
	Commercial alone	702.7	100.0	1.0	--	23.20	--	--
Total Optimum Mix		2,331.0	100.0	0.85	34.52	19.31	132.9	17.29
Total Commercial/Oil Alone		2,331.0	100.0	1.0	6.92	37.86	381.7	--

Savings = \$18.55 x 10^6/yr
Oil saved = 248,800 barrels/yr

EE-T-029

B.2.8 Pensacola, Florida

As discussed in Section 5, a combination of cogeneration and FBC electrical generation systems competes with separate FBC electric and FBC steam systems for the process steam and electricity demand. The optimum (least cost) mix of alternatives depends on the particular magnitude and ratio of electricity and steam demand. At Pensacola, the steam demand is significantly larger than the electrical demand: the ratio of steam to electricity demand is 2.4 compared to a typical ratio of 1.0 for other top ten energy consumers. Assuming the cogeneration system meets the steam demand, there is only a limited electrical demand to consume the electricity "by-product" produced by the cogeneration system. Therefore, at Pensacola, two separate FBC systems are more cost effective than a cogeneration system which would produce excess electricity.

An FBC system also produces heat at Pensacola at $\$3.95/10^6$ Btu, compared to $\$4.08/10^6$ Btu for heat delivered by an RDF system. Energy cost data is presented in Tables B-8a and B-8b. Changes in capital, fuel, operation and maintenance costs for either system could drop RDF energy cost below FBC energy cost. Although this could significantly change the optimum mix of alternatives, the overall monetary savings would remain approximately the same. Further analysis is required to identify the sensitivity of results to changes in cost input parameters.

Even though insolation at Pensacola (1678 Btu/ft^2-day) is high relative to other bases investigated, it cannot support solar thermal or photovoltaic energy systems at costs competitive with conventional sources. A low 9.0 mph wind velocity at Pensacola is typical of the other bases. As a result, wind generators deliver electricity that is nearly three times as expensive as commercial electricity.

Summary

The NES code selected three separate FBC systems together with oil-fired boilers as the optimum mix of alternate energy systems. Additional cost savings are possible if one system were to supply energy to all three energy use sectors. However, this option is not presently available in the NES code. Nevertheless, using three separate FBC systems can reduce annual energy costs by $14 million with an additional capital investment of $23 million. This represents a 2-year payback period and reduces consumption of fuel oil by nearly 85 percent.

TABLE B-8a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR PENSACOLA, FLORIDA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	FBC and oil-fired boilers
	FBC	296.9	428.4	3.95	
	Solar thermal	--	--	(14.48)	
	Conventional coal	--	--	(4.04)	
	Oil-fired boilers	90.5	90.5	9.02	
Process Steam	RDF	--	--	(4.53)	FBC and oil-fired boilers
	FBC	1,182.0	1,446.0	3.70	
	Conventional coal	--	--	(3.94)	
	Cogeneration	--	--	(4.45)	
	Oil-fired boilers	139.5	139.5	9.92	
Electricity	RDF	--	--	(10.60)	FBC and commercial
	FBC	528.7	597.7	8.58	
	Photovoltaic	--	--	(54.14)	
	5-kW wind	--	--	(134.40)	
	200-kW wind	--	--	(64.93)	
	1500-kW wind	--	--	(75.18)	
	Conventional coal	--	--	(99.00)	
	Cogeneration	--	--	(4.46)	
	Commercial	25.3	25.3	23.22	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-030

TABLE B-8b. SUMMARY OF RESULTS: PENSACOLA, FLORIDA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	FBC Oil-fired boilers	296.9 90.5	76.6 23.4	0.69 1.0	4.34 0.49	1.69 0.82	-- 20.27	8.34 --
	Oil-fired boilers alone	387.5	100.0	1.0	1.11	3.33	86.47	--
Steam	FBC Oil-fired boilers	1,182.0 139.5	89.5 10.5	0.82 1.0	10.27 1.51	5.34 1.38	-- 34.55	8.34 --
	Oil-fired boilers alone	1,321.5	100.0	1.0	4.23	12.62	327.68	--
Electricity	FBC Commercial	528.7 25.3	95.4 4.6	0.88 1.0	12.17 --	5.13 0.59	-- --	8.34 --
	Commercial alone	554.0	100.0	1.0	--	12.86	--	--
Total Optimum Mix		2,264.0	100.0	0.83	28.78	14.95	54.82	18.90
Total Commercial/Oil Alone		2,264.0	100.0	1.0	5.34	28.81	414.15	--

Savings = $13.9 x 10^6/yr
Oil saved = 359,300 barrels/yr

EE-T-031

B.2.9 Bremerton, Washington

The relative magnitude of steam to electricity demand economically supports a combination of cogeneration and FBC electrical generation systems rather than two separate FBC steam and electric systems. RDF produces heat and process steam at a lower cost than any other conventional or alternate energy source. However, overall cost for energy is minimized when RDF supplies a portion of the steam demand and FBC supplies heat. Although RDF typically supplies heat at the other bases, Bremerton's larger heating demand is best met by FBC because of its attendant economies of scale.

Bremerton has a low insolation (1117 Btu/ft^2-day) with a corresponding high cost for energy produced by solar thermal and photovoltaic systems. But high wind velocity (9.4 mph) at Bremerton enables wind generators to produce electricity at the relatively low cost of \$32/10^6 Btu (see Table B-9a). At \$14/10^6 Btu commercial electricity is quite inexpensive in the Bremerton area. At higher commercial prices like at Norfolk, Virginia or San Diego, California, wind systems would be cost-effective.

Summary

Investing an additional \$24 million in FBC, RDF, cogeneration, and oil-fired boilers rather than oil-fired boilers alone yields an annual energy cost savings of \$4.6 million. This represents a 5-year payback period, which is high compared with the 2-year payback typical of other locations. Because cheap electricity is available at Bremerton, reducing consumption of commercial electricity does not net significant cost savings. However, replacing oil-fired boilers with FBC's and RDF can reduce oil consumption by nearly 90 percent.

TABLE B-9a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR BREMERTON, WASHINGTON

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	FBC and oil-fired boilers
	FBC	682.6	1,115.0	4.19	
	Solar thermal	--	--	(20.21)	
	Conventional coal	--	--	(4.49)	
	Oil-fired boilers	61.9	61.9	8.64	
Process Steam	RDF	42.2	42.2	4.53	RDF, cogeneration, and oil-fired boilers
	FBC	--	--	(4.92)	
	Conventional coal	--	--	(5.21)	
	Cogeneration	518.4	606.5	5.61	
	Oil-fired boilers	104.9	104.9	9.34	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, and commercial
	FBC	365.2	378.1	10.83	
	Photovoltaic	--	--	(105.13)	
	5-kW wind	--	--	(69.00)	
	200-kW wind	--	--	(42.69)	
	1500-kW wind	--	--	(31.85)	
	Conventional coal	--	--	(12.36)	
	Cogeneration	103.8	103.8	5.61	
	Commercial	54.7	54.7	14.12	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-032

TABLE B-9b. SUMMARY OF RESULTS: BREMERTON, WASHINGTON

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	FBC	682.6	91.7	0.61	8.10	4.68	--	7.29
	Oil-fired boilers	61.9	8.3	1.0	0.27	0.53	13.8	--
	Oil-fired boilers alone	744.5	100.0	1.0	1.89	6.19	166.2	--
Steam	RDF	42.2	6.3	1.0	0.79	0.19	--	0.87
	Cogeneration	518.4	77.9	0.85	9.31	3.98	--	5.34
	Oil-fired boilers	104.9	15.8	1.0	0.91	0.98	23.4	--
	Oil-fired boilers alone	665.6	100.0	1.0	2.13	6.19	148.6	--
Electricity	FBC	365.2	69.7	0.97	9.03	4.09	--	5.68
	Cogeneration	103.8	19.8	1.0	--	--	--	--
	Commercial	54.7	10.5	1.0	--	0.77	--	--
	Commercial alone	523.7	100.0	1.0	--	7.39	--	--
Total Optimum Mix		1,933.70	100.0	0.78	28.41	15.22	37.2	19.18
Total Commercial/Oil Alone		1,933.70	100.0	1.0	4.02	19.77	314.8	--

Savings = $4.55 x 10^6/yr
Oil saved = 277,600 barrels/yr

EE-T-033

B.2.10 New London, Connecticut

With Coal

The optimum mix of energy systems at New London reflects results obtained for other top ten energy consumers. Heating demand is met by RDF, FBC, and oil-fired boilers. As shown in Table B-10b, the load factor (delivered energy divided by produced energy) was 100 percent for RDF and 80 percent for FBC. This suggests that RDF supplies the base portion of the heating demand while FBC and oil-fired boilers meet the peak demand.

Process steam is supplied by RDF, FBC, cogeneration and oil-fired boilers. In this case, RDF and FBC combine to supply the base steam demand with cogeneration and oil-fired boilers supplying peak demand. The procedure used by the NES code to identify the combination of systems that meet base and peak demand was discussed in Section B.1. However, because RDF steam is cheaper than FBC steam ($4.53/10^6$ Btu versus $5.51/10^6$ Btu), and additional refuse is available (refuse is not totally consumed in the heating sector), it appears further cost reductions are possible by using a larger RDF system. Further analysis is required to clarify the NES code's choice of this particular combination.

Typical of other bases investigated, FBC and cogeneration combine to supply nearly 95 percent of the electrical demand. The remaining electricity is purchased from a local utility.

Both insolation (1243 Btu/ft^2-day) and wind velocity are low at New London. Consequently, costs for heat produced by a solar thermal and electricity produced by a photovoltaic system or wind generators is prohibitively expensive compared to conventional sources of energy.

Without Coal

Presently, the New London area is not in attainment for particulate pollutants. If federal utility regulations are applied to industrial power systems, additional coal combustion systems could not be constructed at New London until federal air quality standards are achieved. Therefore, only RDF, solar, wind and conventional energy systems compete in the optimization process. Results are given in Tables B-10c and B-10d. The NES code selected RDF to supply electricity. RDF-fired electrical generation minimizes overall energy costs by reducing consumption of expensive commercial electricity ($\$30.21/10^6$ Btu). This is more cost effective than using RDF to reduce consumption of cheaper heat ($\$8.47/10^6$ Btu) or process steam ($\$8.44/10^6$ Btu) supplied by oil-fired boilers.

Summary

If coal combustion systems are permitted in the New London area, a mix of FBC, RDF, cogeneration, and oil-fired boilers could markedly reduce expenditures for energy. Although this requires an additional capital investment of $24 million, it would cut annual cost for energy by $10 million and reduce oil consumption by 75 percent. In contrast, without coal combustion, RDF is the only feasible alternate energy system among those evaluated in this study. The RDF plant would require an investment of $1.1 million and realize an annual savings of only $450,000. There is the same 2.5-year payback period with or without the coal combustion systems.

TABLE B-10a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR NEW LONDON, CONNECTICUT

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	18.7	18.7	4.08	RDF, FBC, and oil-fired boilers
	FBC	598.9	745.0	4.34	
	Solar thermal	--	--	(15.59)[a]	
	Conventional coal	--	--	(4.50)	
	Oil-fired boilers	260.0	260.0	9.09	
Process Steam	RDF	16.0	16.0	4.53	RDF, FBC, cogeneration, and oil-fired boilers
	FBC	232.0	232.0	5.51	
	Conventional coal	--	--	(4.69)	
	Cogeneration	338.3	427.4	5.67	
	Oil-fired boilers	115.1	115.1	9.31	
Electricity	RDF	--	--	(10.60)	FBC, cogeneration, and commercial
	FBC	300.5	384.4	10.71	
	Photovoltaic	--	--	(88.19)	
	5-kW wind	--	--	(90.36)	
	200-kW wind	--	--	(49.22)	
	1500-kW wind	--	--	(42.25)	
	Conventional coal	--	--	(12.01)	
	Cogeneration	73.2	73.2	5.67	
	Commercial	21.8	21.8	30.21	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-034

TABLE B-10b. SUMMARY OF RESULTS: NEW LONDON, CONNECTICUT

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 $)	Total Annual Cost (10^6 $)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	18.7	2.1	1.0	0.32	0.08	--	0.35
	FBC	598.9	68.3	0.80	6.23	3.23	--	3.87
	Oil-fired boilers	260.0	29.6	1.0	1.87	2.36	58.03	--
	Oil-fired boilers alone	877.6	100.0	1.0	2.97	7.42	195.9	--
Steam	RDF	16.0	2.3	1.0	0.30	0.07	--	0.33
	FBC	232.0	33.1	1.0	3.13	1.28	--	1.34
	Cogeneration	338.3	48.2	0.79	6.86	2.84	--	2.99
	Oil-fired boilers	115.1	16.4	1.0	0.98	1.07	28.5	--
	Oil-fired boilers alone	701.5	100.0	1.0	2.24	6.53	174.0	--
Electricity	FBC	300.5	76.0	0.78	9.13	4.12	--	4.59
	Cogeneration	73.2	18.5	1.0	--	--	--	--
	Commercial	21.8	5.5	1.0	--	0.66	--	--
	Commercial alone	395.5	100.0	1.0	--	11.95	--	--
Total Optimum Mix		1,975.0	100.0	0.86	28.82	15.71	86.57	13.47
Total Commercial/Oil Alone		1,975.0	100.0	1.0	5.21	25.90	369.9	--

Savings = $10.19 x 10^6/yr
Oil saved = 283,300 barrels/yr

EE-T-035

TABLE B-10c. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR NEW LONDON, CONNECTICUT NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	--	--	(4.08)[a]	Oil-fired boilers
	Solar thermal	--	--	(15.59)	
	Oil-fired boilers	877.6	877.6	8.47	
Process Steam	RDF	--	--	(4.53)	Oil-fired boilers
	Oil-fired boilers	701.5	701.5	8.44	
Electricity	RDF	22.7[b]	22.7	10.60	RDF and commercial
	Photovoltaic	--	--	(88.19)	
	5-kW wind	--	--	(90.36)	
	200-kW wind	--	--	(49.22)	
	1500-kW wind	--	--	(42.25)	
	Commercial	372.7	372.7	30.21	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.
[b]Limit of available refuse -- 30 ton/day

EE-T-036

TABLE B-10d. SUMMARY OF RESULTS: NEW LONDON, CONNECTICUT NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Oil-fired boilers	877.6	100.0	1.0	2.97	7.42	195.9	--
	Oil-fired boilers alone	877.6	100.0	1.0	2.97	7.42	195.9	--
Steam	Oil-fired boilers	701.5	100.0	1.0	2.24	5.92	174.0	--
	Oil-fired boilers alone	701.5	100.0	1.0	2.24	5.92	174.0	--
Electricity	RDF Commercial	22.8 372.7	5.7 94.3	1.0 1.0	1.11 --	0.24 11.26	-- --	0.98 --
	Commercial alone	395.5	100.0	1.0	--	11.95	--	--
Total Optimum Mix		1,975.0	100.0	1.0	6.32	24.84	369.9	6.22
Total Commercial/Oil Alone		1,975.0	100.0	1.0	5.21	25.29	369.9	--

Savings = \$450,000/yr
Oil saved = 0 barrels/yr

EE-T-037

B.3 SAMPLE SURVEY BASES

Based upon the availability of weather and fuel consumption data, a set of sample bases was chosen to represent Navy bases with demands less than 1.0 x 10^{12} Btu/year. Kingsville, Texas; Glenview, Illinois; Atlanta, Georgia; and Fort Lauderdale, Florida were selected. Again, the NES code was used to determine the optimum mix of alternate and conventional energy systems which minimizes overall cost for energy. The aggregate results of the sample bases were discussed in Section 6.1. In this section, we present the results obtained by the NES code for each individual base.

B.3.1 Glenview, Illinois

With Coal

The heating demand at Glenview is met by a conventional suspension-fired coal combustion system and oil-fired boilers. This combination contrasts with results of the top ten bases where FBC coal combustion typically supplied heat. But for smaller size demands characteristic of the survey bases, conventional coal combustion is less expensive than FBC systems in all three energy use sectors. For example, as shown in Table B-11a, heat produced by conventional coal and FBC systems costs $4.51/10^6 Btu and $5.01/10^6 Btu, respectively. However, the fraction of time the conventional coal system is active at Glenview is quite low. As indicated in Table B-11b, the ratio of delivered energy to maximum possible produced energy is only 62 percent. This is due to Glenview's northern location, where the monthly heating demand varies tremendously during the year, resulting in considerable downtime during the summer months.

The process steam and electrical demand is met primarily by a steam topping, cogeneration system. Electricity is also supplied by an RDF system which consumes all 4.5 tons/day of available refuse.

Average insolation (1330 Btu/ft^2-day) and wind velocity (9.3 mph) at Glenview are inadequate to economically support solar or wind systems. Energy produced by solar thermal, photovoltaic, and wind energy systems is twice as expensive as energy produced by oil-fired boilers and purchases of commercial electricity.

Without Coal

The Glenview region does not currently meet proposed federal air quality standards for particulate pollutants. Until these standards are

attained, no new utility coal combustion systems can be built in the area. If this restriction is also applied to industrial systems, the Glenview naval facility cannot implement coal combustion. Results of the NES code excluding coal systems are given in Tables B-11c and B-11d. RDF supplies process steam, although production is limited by available refuse -- 4.5 tons/day. Typically, as was the case for the top ten energy consumers, RDF would supply electricity. But at Glenview, the cost of commercial electricity is relatively low, and RDF is most cost-effective when used to supply process steam.

Summary

Assuming coal combustion systems are permitted in the Glenview area, a mix of systems including conventional coal combustion, cogeneration, and RDF can reduce annual cost for energy by $530,000 and cut fuel consumption by conventional oil-fired boilers by 78 percent. This would require an additional $4.18 million capital investment with an 8-year payback period.

If coal combustion is restricted due to nonattainment, RDF is the only viable alternate energy source. An RDF system would cost $140,000, reduce annual energy cost by only $30,000, and cut fuel oil consumption by 1740 barrels/yr. This represents a 4-year payback period.

GLENVIEW, ILLINOIS

rced : Cost Btu)	Optimum Mix
08)[b] 01) 64) 51 .08	Conventional coal and oil-fired boilers
53) 77) 15) .64 .18	Cogeneration and oil-fired boilers
.60 32) 57) .04) 58) 26) .41) 53 .70	RDF, cogeneration and commercial

TABLE B-11b. SUMMARY OF RESULTS: GLENVIEW, ILLINOIS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Conventional coal Oil-fired boilers	105.30 47.73	68.95 31.05	0.62 1.0	2.29 0.27	0.76 0.43	-- 10.59	0.88 --
	Oil-fired boilers alone	152.73	100.0	1.0	0.52	1.33	34.09	--
Steam	Cogeneration Oil-fired boilers	78.71 6.35	92.54 7.46	0.78 1.0	2.16 0.08	0.67 0.07	-- 1.42	0.71 --
	Oil-fired boilers alone	85.06	100.0	1.0	0.27	0.81	21.09	--
Electricity	RDF Cogeneration Commercial	3.30 17.26 7.19	11.88 62.21 25.91	0.97 1.0 1.0	0.17 -- --	0.04 -- 0.13	-- -- --	0.15 -- --
	Commercial alone	27.74	100.0	1.0	--	0.49	--	--
Total Optimum Mix		265.53	100.0	0.76	4.97	2.10	12.01	1.73
Total Commercial/Oil Alone		265.53	100.0	1.0	0.79	2.63	55.18	--

Savings = \$530,000/yr
Oil saved = 41,100 barrels/yr

EE-T-045

TABLE B-11c. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR GLENVIEW, ILLINOIS NOT INCLUDING COAL SYSTEMS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost (\$/10^6 Btu)	Optimum Mix
Heating	RDF[a]	--	--	(4.08)[a]	Oil-fired boilers
	Solar thermal	--	--	(19.64)	
	Oil-fired boilers	152.8	152.8	8.69	
Process Steam	RDF	7.18[b]	7.18	4.53	RDF and oil-fired boilers
	Oil-fired boilers	77.88	77.88	9.58	
Electricity	RDF	--	--	(10.60)	Commercial
	Photovoltaic	--	--	(80.57)	
	5-kW wind	--	--	(83.04)	
	200-kW wind	--	--	(45.68)	
	1500-kW wind	--	--	(39.26)	
	Commercial	27.74	27.74	17.70	

[a]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.
[b]Limit of available refuse -- 4.5 ton/day

EE-T-046

TABLE B-11d. SUMMARY OF RESULTS: GLENVIEW, ILLINOIS (NOT INCLUDING COAL SYSTEMS)

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En./Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Oil-fired boilers	152.8	100.0	1.0	0.52	1.33	34.13	--
	Oil-fired boilers alone	152.8	100.0	1.0	0.52	1.33	34.09	--
Steam	RDF Oil-fired boilers	7.18 77.88	8.4 91.6	1.0 1.0	0.14 0.26	0.03 0.75	-- 19.31	0.15 --
	Oil-fired boilers alone	85.06	100.0	1.0	0.27	0.81	21.09	--
Electricity	Commercial	27.74	100.0	1.0	--	0.49	--	--
	Commercial alone	27.74	100.0	1.0	--	0.49	--	--
Total Optimum Mix		265.61	100.0	1.0	0.92	2.60	53.44	0.15
Total Commercial/Oil Alone		265.61	100.0	1.0	0.79	2.63	55.18	--

Savings = \$30,000/yr
Oil saved = 1,790 barrels/yr

EE-T-047

B.3.2 Kingsville, Texas

Process steam at Kingsville is primarily supplied by cogeneration (85 percent) with the remainder supplied by oil-fired boilers. Although both RDF and conventional coal systems deliver process steam at lower cost than cogeneration, overall energy cost is minimized when a cogeneration system displaces expensive commercial electricity.

All refuse available at Kingsville (8 tons/day) is used to generate heat. This meets 45 percent of the demand, while oil-fired boilers meet the remaining 55 percent.

With an average wind velocity of 14 knots, Kingsville, Texas could economically support wind generators. As noted in Table B-12a, cost for electricity produced by a 1500-kW wind generator is only $\$13/10^6$ Btu compared to a commercial electricity cost of $\$25/10^6$ Btu. However, electricity produced by either conventional coal combustion or cogeneration is even less expensive than that produced by wing generators. Conventional coal combustion costs $\$12/10^6$ Btu and cogeneration is $\$6/10^6$ Btu. Therefore, although electricity generated by wind systems is less expensive than commercial electricity, conventional coal and cogeneration systems remain the optimum mix.

Summary

Investing $4.7 million in RDF, conventional coal and cogeneration systems can yield a $1.2 million reduction in annual expenditures for energy. This represents a 4-year payback period and cuts fuel oil consumption by 13,400 barrels/yr.

TABLE B-12a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR KINGSVILLE, TEXAS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	12.34[a]	14.19	4.08	RDF and oil-fired boilers
	FBC	--	--	(8.06)[b]	
	Solar thermal	--	--	(18.78)	
	Conventional coal	--	--	(6.56)	
	Oil-fired boilers	14.64	14.64	9.49	
Process Steam	RDF	--	--	(4.53)	Cogeneration and oil-fired boilers
	FBC	--	--	(6.53)	
	Conventional coal	--	--	(5.92)	
	Cogeneration	42.95	50.08	6.09	
	Oil-fired boilers	7.49	7.49	10.51	
Electricity	RDF	--	--	(10.60)	Cogeneration, conventional coal, and commercial
	FBC	--	--	(11.62)	
	Photovoltaic	--	--	(41.34)	
	5-kW wind	--	--	(33.20)	
	200-kW wind	--	--	(23.42)	
	1500-kW wind	--	--	(13.38)	
	Conventional coal	80.68	92.42	11.85	
	Cogeneration	8.57	8.57	6.09	
	Commercial	9.43	9.43	25.19	

[a]Limit of available refuse -- 8 ton/day
[b]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-040

TABLE B-12b. SUMMARY OF RESULTS: KINGSVILLE, TEXAS

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF Oil-fired boilers	12.34 14.64	45.7 54.3	0.87 1.0	0.24 0.12	0.06 0.14	-- 3.27	0.26 --
	Oil-fired boilers alone	26.98	100.0	1.0	0.14	0.24	6.02	--
Steam	Cogeneration Oil-fired boilers	42.95 7.49	85.14 14.86	0.86 1.0	1.24 0.07	0.36 0.08	-- 1.86	0.35 --
	Oil-fired boilers alone	50.44	100.0	1.0	0.16	0.49	12.51	--
Electricity	Conventional coal Cogeneration Commercial	80.68 8.57 9.43	81.8 8.7 9.5	0.87 1.0 1.0	3.63 -- --	1.10 -- 0.24	-- -- --	0.13 -- --
	Commercial alone	98.68	100.0	1.0	--	2.49	--	--
Total Optimum Mix		176.11	100.0	0.90	5.03	1.98	5.13	1.74
Total Commercial/Oil Alone		176.11	100.0	1.0	0.30	3.22	18.53	--

Savings = \$1,240,000/yr
Oil saved = 13,400 barrels/yr

EE-T-041

B.3.3 Atlanta, Georgia

The optimum mix of energy systems at Atlanta reflects the general trends noted in Section 6. The average 6.5 mph wind velocity and insolation of 1297 Btu/ft^2-day are inadequate to economically support wind and solar systems. Cogeneration supplies 84 percent of the process steam requirements, and along with conventional coal combustion supplies 85 percent of the electrical requirements. NES results are listed in Tables B-13a and B-13b.

RDF is the only alternate energy system that is cost-competitive with oil-fired boilers in the heating sector. Therefore, 1.5 tons/day of refuse available at Atlanta is entirely consumed to meet heating demand.

Summary

Investing $1.1 million in alternate energy systems will reduce annual energy cost by $130,000 and cut fuel oil consumption by 35 percent. This represents a lengthy 8.5-year payback period.

TABLE B-13a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR ATLANTA, GEORGIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF	2.52[a]	2.52	4.08	RDF and oil-fired boilers
	FBC	--	--	(13.97)[b]	
	Solar thermal	--	--	(15.99)	
	Conventional coal	--	--	(9.37)	
	Oil-fired boilers	16.17	16.17	9.05	
Process Steam	RDF	--	--	(4.53)	Cogeneration and oil-fired boilers
	FBC	--	--	(10.15)	
	Conventional coal	--	--	(7.91)	
	Cogeneration	6.85	7.88	7.65	
	Oil-fired boilers	1.36	1.36	10.42	
Electricity	RDF	--	--	(10.60)	Cogeneration, conventional coal, and commercial
	FBC	--	--	(17.70)	
	Photovoltaic	--	--	(85.32)	
	5-kW wind	--	--	(127.40)	
	200-kW wind	--	--	--	
	1500-kW wind	--	--	(68.09)	
	Conventional coal	12.62	13.71	14.88	
	Cogeneration	1.35	1.35	7.65	
	Commercial	2.60	2.60	23.55	

[a]Limit of available refuse -- 1.5 ton/day
[b]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-038

TABLE B-13b. SUMMARY OF RESULTS: ATLANTA, GEORGIA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En./Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	RDF	2.52	13.5	1.0	0.045	0.011	--	0.049
	Oil-fired boilers	16.17	86.5	1.0	0.091	0.15	3.61	--
	Oil-fired boilers alone	18.69	100.0	1.0	0.095	0.17	4.17	--
Steam	Cogeneration	6.85	83.5	0.87	0.28	0.07	--	0.055
	Oil-fired boilers	1.36	16.5	1.0	0.011	0.014	0.30	--
	Oil-fired boilers alone	8.21	100.0	1.0	0.026	0.078	1.83	--
Electricity	Conventional coal	12.62	72.2	0.92	0.79	0.20	--	0.17
	Cogeneration	1.35	8.1	1.0	--	--	--	--
	Commercial	2.60	15.7	1.0	--	0.061	--	--
	Commercial alone	16.57	100.0	1.0	--	0.39	--	--
Total Optimum Mix		43.47	100.0	0.95	1.22	0.51	3.91	0.27
Total Commercial/Oil Alone		43.47	100.0	1.0	0.12	0.64	6.00	--

Savings = \$130,000/yr
Oil saved = 2090 barrels/yr

EE-T-039

B.3.4 Fort Lauderdale, Florida

The Weapon Center Detachment at Fort Lauderdale consists of only two buildings. For this small size, most alternate energy sources are not cost effective. For example, the amount of refuse produced is too small to support RDF. This was confirmed by the NES code. As indicated in Table B-14a, only a conventional coal system producing electricity is cost-competitive with conventional energy sources. However, extrapolating cost and performance data based on large systems (greater than 10×10^9 Btu/year) to smaller sizes such as Fort Lauderdale probably yields inaccurate data. Separate analyses for extremely small energy consumers should be conducted.

TABLE B-14a. OPTIMUM MIX OF ALTERNATE ENERGY SYSTEMS FOR FORT LAUDERDALE, FLORIDA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Produced Energy (10^9 Btu/yr)	Produced Energy Cost ($/$10^6$ Btu)	Optimum Mix
Heating	RDF[a]	--	--	(4.08)[b]	Oil-fired boilers
	FBC	--	--	(20.47)	
	Solar thermal	--	--	(14.48)	
	Conventional coal	--	--	(11.99)	
	Oil-fired boilers	0.47	0.47	8.48	
Process Steam	RDF[a]	--	--	(4.53)	Oil-fired boilers
	FBC	--	--	(22.15)	
	Conventional coal	--	--	(13.10)	
	Cogeneration	--	--	(13.45)	
	Oil-fired boilers	0.46	0.46	9.56	
Electricity	RDF[a]	--	--	(10.60)	Conventional coal and commercial
	FBC	--	--	(25.37)	
	Photovoltaic	--	--	(54.16)	
	5-kW wind	--	--	(134.40)	
	200-kW wind	--	--	(64.90)	
	1500-kW wind	--	--	(75.18)	
	Conventional coal	3.28	3.49	18.13	
	Cogeneration	--	--	(13.45)	
	Commercial	0.42	0.42	27.34	

[a]Limit of available refuse -- 0.0 ton/day

[b]All parentheses denote: energy costs based on the energy produced by the largest optimum model within each energy use sector.

EE-T-042

TABLE B-14b. SUMMARY OF RESULTS: FORT LAUDERDALE, FLORIDA

Energy Use	Model	Delivered Energy (10^9 Btu/yr)	Fraction of Demand Met (%)	Delivered En. / Produced En.	Initial Capital Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Equivalent Oil Consumption (10^3 barrels/yr)	Area Required (10^4 ft^2)
Heating	Oil-fired boilers	0.47	100.0	1.0	0.0010	0.0040	0.11	--
	Oil-fired boilers alone	0.47	100.0	1.0	0.0010	0.0040	0.11	--
Steam	Oil-fired boilers	0.46	100.0	1.0	0.0015	0.0044	0.11	--
	Oil-fired boilers alone	0.46	100.0	1.0	0.0015	0.0049	0.11	--
Electricity	Conventional coal Commercial	3.28 0.42	88.77 11.23	0.94 1.0	0.27 --	0.063 0.011	-- --	0.43 --
	Commercial alone	3.70	100.0	1.0	--	0.10	--	--
Total Optimum Mix		4.63	100.0	0.96	0.27	0.083	0.22	0.43
Total Commercial/Oil Alone		4.63	100.0	1.0	0.0025	0.11	0.22	--

Savings = \$26,000/yr
Oil saved = 0 barrels/yr

EE-T-043